How and Why Customers Respond to Electricity Price Variability:

A Study of NYISO and NYSERDA 2002 PRL Program Performance

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A Study of NYISO and NYSERDA 2002 PRL Program Performance

Prepared for

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New York State Energy Research and Development Authority

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Executive Summary

How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance

Overview

This summer was the second year of operation for the New York Independent System Operator's (NYISO) suite of Price Responsive Load (PRL) Programs: the Day-Ahead Demand Response Program (DADRP), the Emergency Demand Response Program (EDRP), and the third year of operation for the Installed Capacity Program/Special Case Resources (ICAP/SCR) program. It also marked the second year that the New York State Energy Research Authority (NYSERDA) provided funding to support participation in these programs. NYISO and NYSERDA commissioned Neenan Associates to conduct a comprehensive evaluation of the performance of these PRL programs, building on methods and protocols developed last year and augmented by significant professional staff resources provided by the Consortium for Electric Reliability Technology Solutions (CERTS) with U.S. Department of Energy (DOE) funding.

The PRL program evaluation was undertaken from three perspectives. The first, top-down, perspective looks at the overall impact of PRL programs on New York electricity market prices and system reliability. Quantifying price impacts involves simulating what prices would have been had the curtailments not been undertaken. A supply model developed last year was used to reconstruct this year's market supply curve and estimate the change in hourly prices due to PRL-induced curtailments. Reliability impacts were estimated by valuing the improvement in reliability associated with curtailments undertaken through the EDRP and ICAP/SCR programs, which were jointly administered during 2002.

The second perspective explores why some customers chose to participate while others did not and characterizes the strategies participants employed to curtail when the opportunity or obligation arose and quantifies their performance during events. A variety of statistical analyses and behavioral models were developed from data collected by a survey administered to both participants and non-participants. More in-depth interviews were conducted with a sub-set of

survey respondents to further characterize the decision process that customers undertook when evaluating PRL participation opportunities.

The third perspective examines demand response from the vantage of market entities that have incorporated or may incorporate these services into their business model by analyzing demand response as a business opportunity. A combination of survey data, collected from entities such as load-serving entities, curtailment service providers, control and information technology vendors and performance contractors, and financial models were used to characterize expectations for returns from subscribing customers to the NYISO's PRL programs.

EDRP Program Description and Performance

NYISO solicits curtailable load from its EDRP participants to be dispatched on two hours notice to meet anticipated reserve shortfalls. Customers pledge curtailable load through either one of the state's default or competitive load serving entities (LSE), a curtailment service provider (CSP), as a limited customer (to PRL programs), or as a direct-serve customer. Loads curtailed during EDRP events are paid the greater of $500/MWH or the prevailing real-time, locational-based marginal price (LBMP). For most curtailment events in 2002, as was the case in 2001, the floor price of $500/MWH prevailed.

Curtailment performance in each event hour is measured as the difference between the participant's baseline load (CBL), which is the average usage during that hour on the five highest of the ten most recent like days, and its metered use in that hour. Retail customers that offer their load curtailment capability in the Installed Capacity/Special Case Resources (ICAP/SCR) program through a Responsible Interface Party (RIP) were also allowed to subscribe to EDRP in 2002, thereby making them eligible for EDRP energy curtailment payments in addition to the amount they received from the sale of their ICAP/SCR capacity.

Enrollment in EDRP increased dramatically to 1,711 in 2002 compared to 292 in 2001. Moreover, EDRP participants in 2002 subscribed more load for curtailment, 1481 MW, which represents a two-fold increase from 2001 (Fig. E-1). Approximately 58% and

EDRP 2002 Experience

	Participants MW	Events	Load Curtailed	Payment
EDRP 2002	1711 1481 MW	22 hr Downstate 10 hr Upstate	668 MW 34% of CBL *(summer events)*	$3.3 mil
2001	292/712	23/18	425/38%	$4.2

Fig. E-1: EDRP 2002 Summary

69% of 2001 EDRP and ICAP/SCR participants, respectively, re-enrolled in the 2002 programs, an indication of high program satisfaction. Market entry by curtailment service providers (CSP) increased significantly from 12 in 2001 to over 20 in 2002. CSPs aggressively promoted participation in the EDRP program, especially among smaller customers, accounting for over 60% of participating customers and 20% of the load curtailments during summer events. Most of the remaining 40% of participants were enrolled through a regulated LSE and accounted for 56% of the subscribed load reduction capability.

Curtailments under EDRP were called on two consecutive days in the early spring and one day in each of the months of July and August. The EDRP events on April 17th and April 18th began at noon and ended at 6:00 p.m., but curtailments were called for only in the downstate pricing zones. EDRP curtailments on those days were modest, about 70 MW on average, due to the early date on which they occurred. Few of the previous summer's participants were prepared to curtail so early in the season and recruitment for the summer of 2002 had just begun.

The two summer events, on July 30 and August 14, were declared statewide for five hours on each day beginning at 1:00 p.m. and ending at 6:00 p.m. The average hourly curtailment performance over the 10 curtailment hours was about 668 MW, ranging from an hourly low of 550 MW to a high of over 800 MW (Fig. E-2). Curtailments in 2002 exhibited greater variation than those of summer 2001, when curtailments never varied more than 5% from the hourly average for the 18 hours of statewide curtailments.

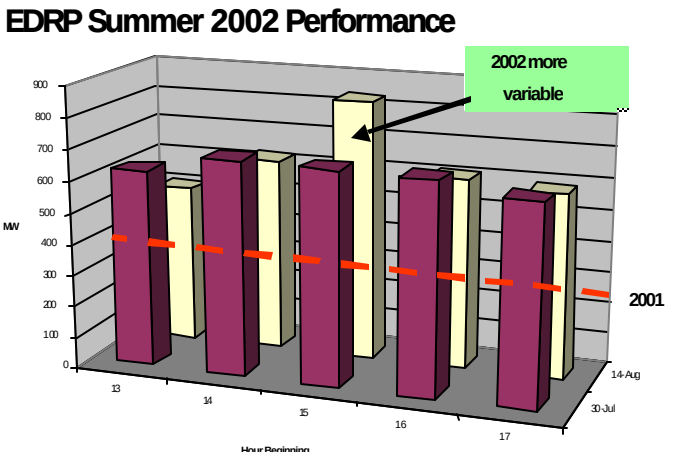


Fig. E-2: EDRP Performance – Summer 2002

In 2002, EDRP participants reduced their hourly electricity usage by an average of 34% compared to their customer baseline (CBL), slightly less than last year. EDRP payments to participants for the summer 2002 events totaled over $3.3 million, about two-thirds of which was for load curtailed in the upstate zones. However, participation and load curtailment activity in 2002 increased in the New York City/Long Island zones, accounting for almost 20% of the

statewide load curtailment response, up from 12% in 2001. Subscription of on-site generation in 2002 was about 270 MW, over twice that of last year.

EDRP Program Effects: Market Impacts and Benefits

The overall strategy for evaluating the 2002 EDRP events utilized protocols and methods developed primarily in Neenan (2002) to measure market impacts and to quantify provider and customer benefits (see Chapter 6).[1] Market impacts include: (1) program costs, which are payments to program participants for verified load reductions, (2) market price impacts, measured by the value of estimated changes in day ahead market (DAM) and real-time market (RTM) electricity prices resulting from load reduction events, and (3) reliability benefits. The market price impacts are comprised of two components: settlement transfers from generators to wholesalers and hedging benefits that reflect the longer run impacts of lower price variance resulting from program curtailments. One would expect that competition would ensure that these benefits eventually inure to retail customers. Another important benefit, the quantification of which was beyond this study's resources, is the reduction in deadweight losses that are associated with DADRP curtailments. Deadweight losses result from retail prices that fail to reflect the underlying marginal cost of supply.

Reliability benefits measure the effect of EDRP load reductions on system reliability as valued by the decrease in expected un-served energy; how an increase in reserves would reduce the likelihood of a forced outage and thereby reduce the costs that customers incur when service is interrupted. These benefits are enjoyed directly by all end-use customers. Fig. E-3 compares estimated collateral,

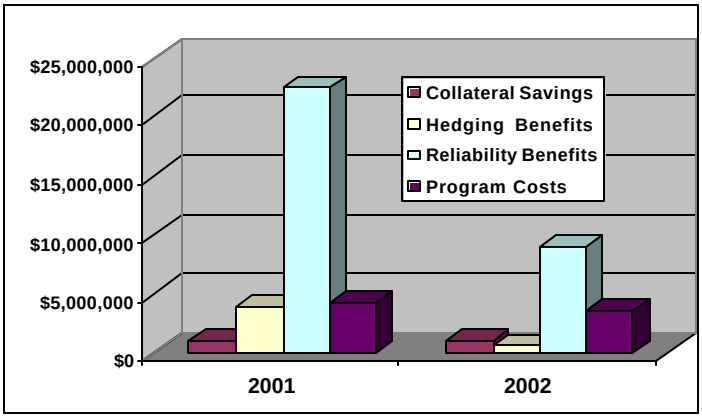


Fig. E-3: Comparison of EDRP Program Costs and Benefits – Summer 2001 vs. 2002

[1] The detailed methodology for estimating these effects is thoroughly documented in Neenan Associates (2002). *NYISO Price-Responsive Load Program Evaluation: Final Report*, Prepared for the New York Independent System Operator, Albany, NY, January 8, 2002.

hedging and reliability benefits for the 2001 and 2002 EDRP program, along with program costs. EDRP load curtailments in 2002 are estimated to have caused a reduction in real-time LBMPs ranging from 4.4% in the Hudson River region to just over 25% in the Western NY region. When applied to the load settled in the real-time market, these price reductions are estimated to have resulted in a transfer of settlement revenue (collateral benefits) from electricity suppliers (generators) to wholesale purchasers of electricity (LSEs) of just over $577,000.

Price reductions in the Real-Time Market also affect bilateral and forward markets, exerting downward pressure on prices as a result of reduced variability. The estimated average price reductions for weekdays for the summer 2002 EDRP events range between $0.04 –to 0.15/MW downstate and slightly higher upstate, $0.20/MW, which translates into total hedging benefits of about $370,000. These values are an order of magnitude lower than the corresponding impacts estimated for the 2001 EDRP program, mostly due to lower overall prices, both after and before the curtailments, during 2002 events compared to the events of 2001.

By restoring reserve margins, EDRP curtailments led to a reduction in the loss of load probability (LOLP), the consequences of which are a reduction in the value of expected un-served energy based on a customer's outage cost. System reliability benefits were analyzed using a range of values for outage costs and the reduction in LOLP to bracket the likely, but unobserved, actual values. Assuming an average outage cost of $5,000/MWh and that 5% of the load was at risk due to a reserve shortfall, the reliability benefits were estimated to range between $1.697 million and $16.9 million, depending on the assumed level of reduction in LOLP at the level of 0.05 and 0.50, respectively.

DADRP Program Description

Retail customers during 2002 were able to bid load curtailments into the NYISO Day-Ahead Market (DAM) by submitting a DADRP bid through a LSE. Curtailment bids were submitted on terms similar to those that apply to generators seeking scheduled commitments to produce for the next day, with two important exceptions. If the NYISO accepts the participant's bid and it curtails the amount scheduled, the participant receives payment equal to the day-ahead LMBP multiplied by the scheduled amount.[2] DADRP bids are subject to a floor price of

[2] Since participants subscribe to DADRP through a LSE, the payment for the curtailment goes to the LSE, which then pays the customer according to the arrangements they have made between themselves.

$50/MWH and the penalty rate for failure to meet the curtailment obligation in the real-time market is 110% of the greater of the prevailing RTM price or the scheduled DAM price. In contrast, generator supply bids in the DAM are not subject to a floor price and generator supply shortfalls in the RTM are settled at the real-time LBMP.

DADRP Program Effects: Market Impacts and Benefits

Customer bidding activity in the 2002 DADRP decreased compared to 2001, despite an increase in customer enrollment (from 16 to 24 customers-Fig. E-4). Payments for DADRP curtailments were about $110,000 in 2002, about half of the previous year's level. The collateral benefits, measured as the price decline associated with DADRP bids times the load scheduled in the DAM, were estimated to be about $236,000.

DADRP 2002 Experience

	Part.	Accepted Bids	Max. Demand	Pymt
DADRP 2002	24	1486 MWH scheduled	~14 MW (average)	$0.1
2001	16	2694	8	$.2

Fig. E-4 DADRP 2002 Experience

Customer Participation and Performance: Who Participates, Why, and How Well?

A primary objective of the 2002 evaluation was to better understand customers' decisions regarding participation and performance in the NYISO Demand Response programs (see Chapters 3, 4 and 5). For system dispatchers to view PRL programs as reliable resources during times of emergency, it is critical to identify and explain differences between subscription rates and actual performance. Moreover, because participant acquisition costs can be high, CSPs, LSEs, and policymakers would like to identify factors that contribute to higher performance yields. To characterize the drivers to participation in PRL programs, a survey was administered to 85 program participants and 59 informed non-participants, the latter comprised of customers that were exposed to the program opportunity, but chose not to participate. The data collected provide a means for comparing and contrasting participants with non-participants, both in terms of

However, regulated LSE tariffs require that the customer be paid 90% of the payment the LSE receives from the NYISO.

observable characteristics and with regard to expressed preferences for program features and provisions.

Customers that participated in one or more of the NYISO's PRL programs are characterized by significantly higher summer peak demand than non-participants. The median maximum demand was 1.7 MW and 14.5 MW for EDRP and DADRP participants, respectively, compared to 750 kW for non-participants. Yet, many customers with relatively small loads, less than 500 kW, enrolled in EDRP and some curtailed proportionally as much or more load.

Among survey respondents, participants with prior experience in one or more utility load management programs were more likely to participate in NYISO PRL programs compared to those with no load management experience. PRL participants were more likely than non-participants (80% to 60%) to have an employee responsible for managing or procuring energy, although the differences are not as large as one might expect. When asked to name the primary impediment to shifting load during the summer day peak period (noon- 6 PM), commercial (80%), institutional (55%) and multi-family (85%) survey respondents overwhelmingly cited occupant comfort. Yet, over 25% of PRL program participants reported turning down lights to accomplish a curtailment and over 20% report that they altered HVAC system operation. One untested hypothesis is that the emergency nature of EDRP events makes relatively infrequent and relatively short (i.e., 2-6 hours) load curtailments tolerable, as they impart an element of public spirit, as is the case with curtailments undertaken for free as a result of public appeals by utilities.

An important focus of this year's survey was to characterize barriers to DADRP participation (see Chapter 4). DADRP offers customers the opportunity to bid against generators on their own price and curtailment terms, and the bids are resolved the day before, unlike EDRP events for which there is only two hours notice. Given customers' aversion to short notice outages, which was quantified by means of behavioral models estimated from survey data (see Chapter 5), one might expect that participation in DADRP would be even more attractive than EDRP, but that has not been the case so far.[3]

Why are customers currently unwilling to participate in DADRP? Analyses of the overall survey results, augmented by in-depth customer interviews conducted with a subset of 35 survey

[3] DADRP has many similarities to RTP programs that have enjoyed high levels of participation in many jurisdictions, for example Georgia Power which as over 1,600 participants, and that are the inspiration for many to propose that such service should be mandatory, at least to the largest customers.

respondents, indicate that a number of organizational, institutional, economic, technical and program-design barriers influence customers' willingness to participate. First, awareness level of the DADRP among survey respondents is low; only 45% of respondents indicated that they were aware of the DADRP program. Only 39% of EDRP and ICAP/SCR participants reported being aware of DADRP, even after two summers' experience. Apparently, LSEs and CSPs in marketing EDRP and ICAP/SCR are not exposing customers to the DADRP participation opportunity, perhaps because they have judged that opportunity to be inherently unattractive to the customer.

What about customers that were aware of DADRP but chose not to participate? Many of these (36%) cited the inability to shift or curtail usage as the primary reason for not participating, which confirms that DADRP is not for everyone (see Fig. E-5). Thirty-five percent indicated that either inadequate compensation or the perceived risks was the primary reason for not participating in DADRP. Paradoxically, many of the customers that rejected DADRP for these reasons participate in ICAP/SCR, which involves very short notice of a curtailment obligation that if not met results in a significant penalty, relative to the benefit. Part of the answer may be in the way customers perceive participation. In the case of EDRP and ICAP/SCR, participants may see themselves as foremost responding to a system emergency, which provides psychic income from acting as a good citizen. Moreover, reducing usage is a rational reaction to the possibility of a forced outage. Thus, it may be easier for an energy manager to sell their management on EDRP compared to bidding in DADRP, which involves market speculation, especially if the supplemental monetary benefits from EDRP are high.

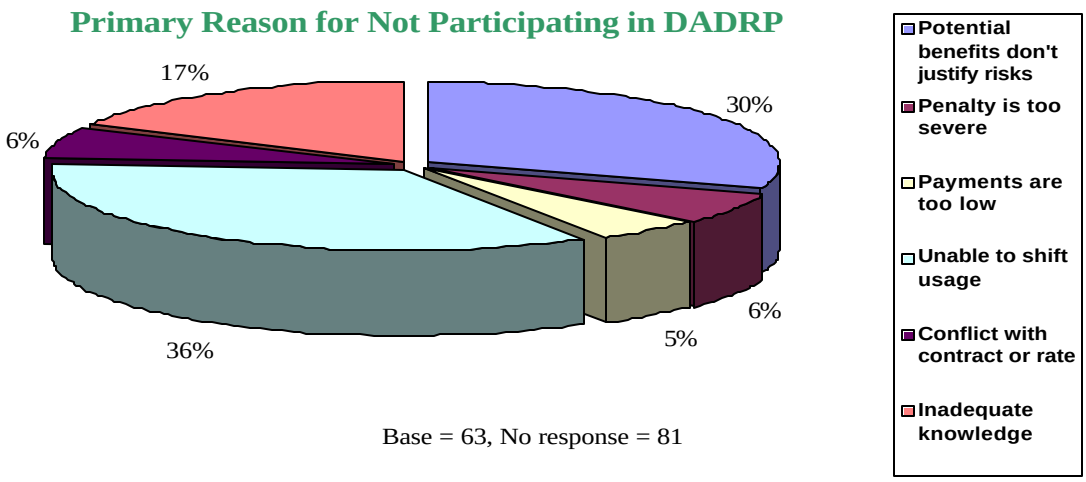
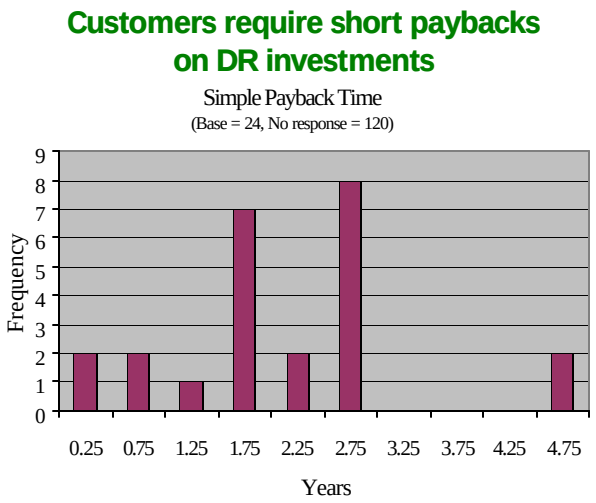


Fig. E-5: Reasons for Not Participating in DADRP

As was the case last year, the survey results indicate that lack of understanding of the benefits and risks of DADRP participation is a very important deterrent to participation. A significant group of non-participants (17%) cited various types of information and education barriers as their primary reason for not joining DADRP. To explore this further, some survey respondents were asked to rate their comfort level in performing the following activities on a 1 (low) to 5 (high) scale: (a) developing a curtailment implementation plan compatible with DADRP bidding, (b) monitoring day-ahead energy prices to determine whether to bid, and (c) developing a bidding strategy based on NYISO DAM and RTM prices. Not surprisingly, 90% of DADRP participants indicated that they were comfortable performing these threeactivities.

In contrast, while 70% of DADRP non-participants reported that they were comfortable creating a load curtailment plan, only 15% indicated that they were comfortable determining at what price to bid. This suggests that many customers that can see themselves curtailing at least some usage do not understand sufficiently the character of NYISO prices to develop a bidding strategy that takes advantage of that capability. These findings highlight the need for additional information, education, and training on how the market works and how prices are tied to observable and predictable market situations.

Customers reported high payback thresholds for investments in enabling control and information technologies (Fig. E-6). In addition, customers indicated that they saw little value for such technologies outside of the existing PRL programs, overlooking that some of these technologies could be used to facilitate participation in other dynamic rate programs, such as TOU, or to minimize demand charges. PRL programs on their own seem unlikely to spur significant investments in control technologies, at least under existing program designs.



Approx. 80% of respondents were interested in a payback of less than 3 years for DR technologies

Fig. E-6: Payback for Demand Response Investments

To analyze the factors that influence customers' EDRP subscription levels and actual event curtailments, a performance metric, called the Subscribed Performance Index (SPI), was developed to compare customers' actual performance during the summer 2002 events relative to what they indicated they could achieve when they subscribed (see Chapter 5). The SPI metric facilitates the comparison of curtailment yield among groups of customers and serves to characterize the impact of dispatching EDRP resources during system emergencies. Table E-1 below summarizes the average performance of different groups of EDRP customers segmented by load curtailment strategy (e.g., load reduction only, on-site generation), program participation choices (e.g., EDRP only vs. EDRP and ICAP/SCR), market segment, and participation in a NYSERDA program. NYSERDA offered funding in 2001 and 2002 under two programs specifically to promote participation in the NYISO's PRL programs.

Table E-1: Performance Results of Selected Customer Groups

	N	Total Subscribed Load (MW)	Mean Customer-specific Subscribed Performance Index (SPI_C)
All Customers	**1,711**	**1,477**	
Curtailment Strategy			
Load Reduction Only	**1,292**	**1,147**	**32%**
On-Site Generation	**373**	**262**	**46%**
Program Choices			
EDRP Only	**1,105**	**429**	**42%**
EDRP and ICAP/SCR	**113**	**455**	**96%**
Market Segment			
Manufacturing	**99**	**558**	**65%**
Government/Utilities	**84**	**123**	**80%**
Education	**33**	**30**	**103%**
Trade	**29**	**26**	**80%**
Health	**16**	**28**	**45%**
Multi-Family/Apartment	**10**	**9**	**37%**
Office Building	**7**	**8**	**123%**
NYSERDA Peak Demand Program			
NYSERDA Program Participant	**111**	**154**	**64%**
Non-NYSERDA Participant	**1107**	**730**	**46%**

The 113 jointly subscribed active EDRP and ICAP/SCR participants curtailed 92% of their subscribed load reduction during the EDRP summer events, which accounted for 52% of the delivered load curtailment during EDRP events. In contrast, on average, the 1,105 active EDRP-

only customers delivered 42% of their subscribed load reduction commitment when called. Overall, actual curtailment performance compared to what was subscribed was more variable for those customers that relied on load reduction strategies relative to those that deployed on-site generation to effect a curtailment.

Participants in the government/utilities, education, and retail/wholesale trade sectors performed quite well during EDRP events, exhibiting mean SPI values ranging from 80-103%. Health care facilities and multi-family buildings had lower mean SPI values of 45% and 37%, respectively. On average, the 111 customers that received funding from NYSERDA and actively participated in EDRP events out-performed the non-NYSERDA participants, as evidenced by SPI values of 64% and 46%, respectively, which indicates the value and contribution of NYSERDA's technical and financial assistance programs.

Demand Response as a Business Case

A major objective of the 2002 evaluation for NYSERDA was to characterize the needs of business entities that are currently serving, or could serve, as retailers of price-responsive load services (see Chapter 7). These include regulated and competitive LSEs that offer electric commodity service, utilities that provide wires services to end-use customers, and other firms that provide related services to customers such as control and information technology vendors, ESCOs offering performance contracting, and curtailment service providers (CSPs) that specialize in facilitating participation in PRL programs.

Two initiatives were undertaken to characterize demand response as a business: a survey of firms to ascertain their criteria for involvement in PRL programs and pro forma financial analyses to characterize the potential bottom line contribution from doing so. These analyses provide policymakers and public benefit fund administrators (e.g., NYSERDA) with insights into the margin contributions that might be expected by various types of entities that recruit customers to DR programs and the potential sustainability of alternative business models under different scenarios.

The survey suggests that while most firms acknowledge that there might be value to incorporating demand response programs into their business offerings, few are willing to use it as a loss leader. In other words, these programs must contribute to the bottom line in order to be worth promoting, and that contribution requires returns of 10% or greater. Virtually all of the

firms contacted favor the use of public benefits funds to accelerate the growth of program participation. Some firms would restrict such expenditures to underwriting investments in enabling technologies or marketing costs. Others would like to see program benefits (for example, the EDRP $/MWH curtailed) supplemented over what the NYISO offers to increase margins from promoting such participation.

Financial analyses were conducted to quantify the potential benefits to serving as a demand response program provider. Pro forma income statements were developed to characterize the costs associated with promoting participation and to quantify the expected revenues, first using the program provisions applicable in 2002 and then under the revised provisions approved for2003. In 2003, participants must choose between ICAP/SCR and EDRP participation, which increases the expected benefits from ICAP/SCR participation and reduces those associated with EDRP participation relative to 2002. DADRP was modeled as a strip option to establish expected benefits of submitting a standing-offer strike price. In all cases, the firm sponsoring participation underwrites the equipment and administrative costs and shares in the payments that the customer earns for curtailing.

Acting as a CSP appears to be a highly speculative business. EDRP does not appear to provide sufficient revenues, assuming that the customers share 40% of the payments from the NYISO, to justify recruiting customers as a stand-alone business, unless customers can be acquired at very low costs or support funding is provided by some entity such as NYSERDA. Expected margins from sponsoring joint EDRP and ICAP/SCR participation downstate were encouraging when viewed from a Spring 2002 perspective based on 2001 EDRP events (i.e., 23 hours) and ICAP prices of around $50/kW. The Net Present Value (NPV) for three years of participation under those conditions was $1.3 –1.6 million.

However, in upstate NY, the low ICAP values generated from the same perspective produced negative expectations for margins. Nevertheless, actual ICAP/SCR and EDRP subscriptions expanded both upstate and downstate in 2002. In some cases that expansion was likely driven by NYSERDA public benefit funding, especially for CSPs, which offset the costs of recruiting and servicing participation. In all cases, actual revenues did not meet expectations since there were only 10 curtailment hours in the summer of 2002 and upstate ICAP values were lower.

Going forward to 2003, curtailable load can be subscribed to either ICAP/SCR or EDRP, but not both. In addition, ICAP/SCR resources will be called on first, which in some cases may preclude the declaration of an EDRP curtailment event, and ICAP/SCR resources will be

dispatched according to the strike price they declare; in some instances, not all of those resources will be paid for curtailing. As a result, ICAP/SCR revenues are expected to decline, and those from EDRP will become more speculative. In upstate NY, the consequencesare that expected returns for recruiting new customers for the next three years are negative. Downstate, promoting and sponsoring ICAP appears to continue to be an attractive business proposition, largely due to the higher ICAP market prices. However, customers that previously participated represent profitable opportunities as most of the transaction costs are sunk.

Participation in DADRP was evaluated to ascertain whether it could be bundled with ICAP/SCR to improve margin prospects. Whether it does or does not depends on the bidding strategy of the participants and DAM market prices over the next 3-5 years. Under optimistic conditions, from a business case perspective, the NPV of such an endeavor is $120/kW downstate and $46/kW upstate. Such conditions include ICAP values persisting at their summer 2002 values and DAM prices that result in extensive curtailments scheduled at a $100/MW strike price. Under the worst-case conditions, where ICAP prices are lower and few curtailments are scheduled, margins downstate are reduced to $13/kW and become highly negative ($34/kW) upstate. However, profitability is very sensitive to customer load acquisition costs.

Summary

The NYISO's PRL programs continue to grow and evolve through experience, and as a result become more effective. Participation in capacity and emergency programs has provided resources that have proven valuable in system emergencies, and laid the foundation for attracting customers to bid curtailments in the day ahead market to further improve market performance. In addition, the exposure to dynamic market prices will make participants more amenable to time-of-use and other pricing options that provide enduring benefits to all stakeholders. NYSERDA's programs have been especially useful in demonstrating the value of enabling technologies and attracting participation from underrepresented sectors. The comprehensive program evaluations these entities have sponsored have served as the basis for refining and adapting these PRL programs. Moreover, the methods and protocols developed provide an important contribution to a more complete understanding of how customers use and value electricity that will benefit many other initiatives to make electricity markets more efficient and effective.

Chapter 1 - NYISO PRL Program Overview

Introduction

The New York Independent System Operator (NYISO) has implemented programs to induce retail customers to adjust their consumption according to prevailing wholesale market conditions. Accordingly, these price-responsive load (PRL) programs have been designed to integrate, to the extent possible, load management actions by customers into NYISO operations.[1] Customers can participate in any program for which they qualify by registering with the NYISO and curtailing their electricity usage under the program provisions and protocols. Some programs also allow customers to operate behind-the-fence generation, generally referred to as distributed generation (DG), during curtailment events to reduce the net load taken from the system, and thereby mimic a load curtailment.[2]

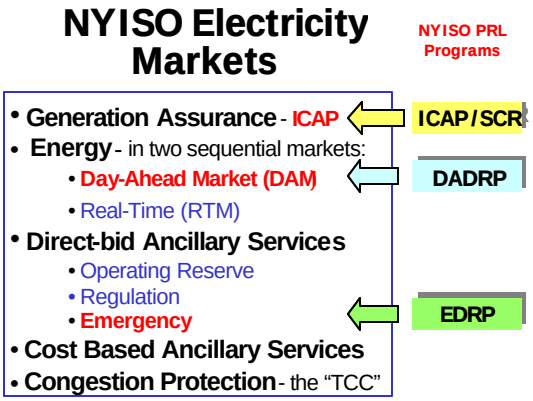


Fig. 1-1 NYISO Electricity Markets

As Fig. 1-2 illustrates, PRL programs are offered for three of the five categories of markets the NYISO oversees. The Installed Capacity Program/Special Case Resources (ICAP/SCR) program utilizes load management capabilities to augment the supply of generation used by the NYISO as standing reserves, which is especially

NYISO PRL Program Features

	Market Function	Eligible	Event Notice	Payment
ICAP	Installed Capacity	> 100 kW	Day-ahead advisory, 2 hour notice	$/kW Market value of ICAP
EDRP	Emergency Capacity	> 100 kW can aggregate	2 hour notice	Greater of $.50/kWh or RTM LBMP
DADRP	Economic Energy	1 MW increments, can aggregate	Bid by 5am, day-ahead, notice by noon	Greater of Bid $/kWh or DAM LBMP

Fig. 1-2: PRL Program Features

[1] The provisions of the PRL programs are authoritatively described in the program manuals that are available from the NYISO.

[2] The NYS Department of Environmental Conservation regulates the operation of small, noncommercial electrical generation units, limiting the conditions under which many such units can operate and thereby limiting participation in NYISO PRL programs.

important in areas of the state that are capacity deficient. The Day-Ahead Demand Response Program (DADRP) allows load curtailment resources to compete against generation in the NYISO's day-ahead auction, which helps ensure competitive bidding behavior. The Emergency Demand Response Program (EDRP) creates a new and unique category of ancillary services that are valuable in maintaining short-term system reliability. The NYISO intends to expand participation of PRL resources to the real-time market and to ancillary service markets. Viewed differently, the existing PRL programs can be classified by the type of physical service they provide to the market. Two PRL programs provide dispatchable capacity to the market, and one provides scheduled energy service. They are described below.

ICAP/SCR and EDRP

The NYISO provides two means by which customers can offer load curtailment capability as a system resource, through its generation assurance market under terms that approximate a call option valued at the market-clearing price of capacity (ICAP/SCR), and as a dispatchable resource that is paid the prevailing market-clearing energy price, subject to a floor price provision, at the time of event (EDRP). The latter can be viewed as an as-available, pay-on-performance arrangement.

Capacity Calls Option - ICAP/SCR

The NYISO requires member Load Serving Entities (LSEs) to secure installed capacity (ICAP) for each six-month capability season equal to about 118% of the load they serve.[3] LSEs can acquire their ICAP requirements through bilateral contracts with qualified generators or purchase their needs from the capacity auctions administered by the NYISO. Retail consumers can register their load curtailment capability as an ICAP Special Case Resource (ICAP/SCR) and either sell that capacity to an LSE directly, or offer it for sale through the NYISO capacity auctions. Customers that make such sales are required to curtail consumption equal to their ICAP/SCR obligation when called upon to do so by the NYISO. System operators dispatch ICAP and ICAP/SCR resources when system reserve shortages are forecast, always with at least two hours notice, but only if prior 24-hour advanced notice was given.[4]

[3] Capability periods begin May 1 and November 1

[4] When the NYISO foresees the need to deploy ICAP resources, it notifies load curtailment resources a day ahead thereby creating the opportunity, but not the obligation, for system operators to call an event the next

Under the 2002 program provisions, ICAP/SCR customers receive the sales value of their capacity and face steep penalties for any failure to comply with curtailment calls, which are substantially the same benefit and penalty provisions under which generators selling ICAP operate. Customers must subscribe at least 100 kW of curtailable load through a Responsible Interface Party (RIP) that, due to the penalty provisions, must meet NYISO credit worthiness requirements.[5] The NYISO allows RIPs to aggregate curtailable loads to meet this requirement or for their commercial purposes. RIPs must ensure that data is read and submitted to the NYISO after events and when tests are invoked to certify the curtailment capability, which are the same conditions applied to generation ICAP.

Curtailment performance under ICAP/SCR is defined by the difference between the participant's capability period-specific CBL (customer baseline load) and its actual metered usage during the event. If the participant utilizes a DG to meet its obligation, it may meter the output of that unit to establish compliance. The CBL is the average non-coincident measured demand for four months of the previous year corresponding to the capability period.[6] To avoid a penalty, the participant must curtail at least as much load as it sold as ICAP/SCR for the capability period. Failure to perform results in a derating of the customer's ICAP/SCR capability, which requires that the participant arrange for an alternative, replacement ICAP resource or face deficiency penalties.[7]

As Available, Pay-on-Performance: EDRP

The Emergency Demand Response Program (EDRP) solicits curtailable load that can be dispatched on two-hour notice to meet anticipated reserve shortfalls. Participants register at least 100 kW of curtailable load through a Curtailment Service Provider (CSP).[8] Smaller customers

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day. Because generators that have sold ICAP are required to schedule or bid an equivalent capacity amount into the day-ahead market, the notice provision is not applicable to them.

[5] Customers can be an LSE themselves by registering as a direct serve customer and thereby act as their own RIP.

[6] Measured Demand during the months of June, July, August, and September are used for the summer capability season CBL, while the months of December, January, February, and March are used for the winter CBL.

[7] The NYISO can also impose a test to ascertain the participant's ability to meet the curtailment requirement, although such tests are generally undertaken only when no curtailment events have been nor are likely to be called in a capability period.

[8] Customers can register to be a direct serve customer or a limited customer, both of which allow the

can participate through a CSP that is willing to aggregate loads to meet the minimum size requirement. In addition to LSEs (that are CSPs by definition), NYISO allows otherwise unaffiliated entities to register as a CSP solely for the purposes for registering customers with NYISO to participate in EDRP. These latter entities do not have to show credit worthiness because no penalties are assessed for nonperformance, as described further below.

When the NYISO determines that EDRP resources are needed, it issues a call that an event has been declared. The event notice also specifies the start and end time for the event, which includes at least four consecutive hours. After declaring an event, the NYISO may extend the event period by notifying customers thereof, and it may cancel the third and fourth hours of a declared event, again by notifying customers prior to the start of the third hour.[9]

Participants that curtail during an event receive the greater of $500/MWH or the applicable prevailing locational-based marginal price (LBMP) of energy for curtailed load, as long as the event is of four or more hours in duration. If the NYISO cancels the event after two hours, customers that continue to curtail receive the LBMP for such curtailments in the third and fourth hours. The NYISO LBMP market cap of $1,000/MWH establishes the maximum EDRP curtailment payment.

Under EDRP, performance is defined as the difference between the participant's hourly CBL (customer baseline load) and its actual metered usage during the event. The CBL for weekdays is defined as the average of the usage, in each event hour, during the five highest usage days out of the last ten days. For weekends, the CBL is the average hourly usage for the two highest usage days out of the previous three corresponding (either Saturday or Sunday) weekend days. In picking the days over which to average, curtailment days are excluded. There is no penalty under EDRP for failure to curtail during an event.

Joint ICAP/SCR and EDRP Subscription

Although the aforementioned demand response programs were designed to serve as a means for participating in different aspects of the NYISO's market, customers were allowed to

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customer to act as its own CSP for purposes of EDRP.

[9] An event cancellation generally results when the system operators, foreseeing a reserve shortfall, calls EDRP early on in the day, and then finds that when the time comes, the resources are not needed. In this case, they would notify customers at the event start time that the event would be cancelled after two hours. This has occurred only once in two years of operation.

subscribe to both the EDRP and ICAP/SCR programs in 2001 and 2002. This accommodation allowed load curtailments to be paid by both programs when ICAP/SCR event calls were coincident with EDRP curtailments opportunities; ICAP/SCR provided an upfront payment ($/kW) and EDRP provided an energy payment ($/kWh), which enhanced both programs' participation benefits.

However, ICAP/SCR obligations were separately measured from EDRP curtailments. To ascertain whether or not an ICAP/SCR participant met its obligation, its event demand was compared to its ICAP/SCR requirement, using the CBL based on the past summer's maximum demand. Then, the EDRP CBL, which measures performance relative to recent average hourly usage, was applied to each event hour to determine the level of EDRP curtailments that were paid at the EDRP energy rate. As a result, a customer could be deemed to not have fulfilled its ICAP/SCR obligation and yet receive EDRP payments, since EDRP has no noncompliance penalty.

PRL Energy Program: DADRP

Retail customers can bid load curtailments into the NYISO's day-ahead market through any LSE that accommodates program participation. DADRP curtailment bids, which are subject to a $50/MWH floor and a $1,000/MWH ceiling, include a $/MWH price and bid conditioning provisions, such as minimum and maximum curtailment levels each hour, and a requirement that curtailments be scheduled over a fixed block of hours. If the bid is scheduled, the participant is considered to have contracted with the NYISO to deliver the curtailment the next day as specified, commensurate with a scheduled generation bid into the day-ahead market. If the bid is not scheduled, then the participant reverts to the provisions of its retail service arrangement.

If the participant curtails the amount scheduled, a payment equal to the day-ahead LBMP times the scheduled amount (and only that amount, there is no credit for over-performance) is paid to the LSE. The LSE receives a credit in the same amount, which eliminates its exposure to differences between the day-ahead and real-time LBMPs.[10] If the participant fails to curtail the

[10] When the participant curtails, the result is that the LSE is put into a long position; it has scheduled generation in excess of what it will serve if it had covered that participant's load either with a bilateral contract or through a price cap load bid accepted in the day-ahead market. That long position would otherwise be closed in the real-time market by a payment to the LSE for the curtailment amount at the real-time LBMP. As a result, the scheduling of a DADRP bid exposes the LSE to the day-ahead/real-time price spread, which can be positive or negative. By crediting the LSE in the DAM with the same amount that the participant receives for the curtailment, the LSE is made whole; it buys the curtailment amount in the DAM

amount scheduled in any hour of the scheduled event, the LSE is charged with a penalty equal to 110% of the greater of the scheduled day-ahead LBMP or the real-time LBMP. All payments for curtailments and assessments of noncompliance penalties are made by the NYISO to the LSE. The contract between the LSE and the participant determines how the flow of funds impacts the participant.[11] The curtailment performance determination and metering requirements are the same as for EDRP.

2002 Program Participation

Appendix 6A contains extensive tables and graphs that summarize PRL participation in 2002 by program, zone, sponsor, and other distinguishing factors. The adjacent table summarizes EDRP and DADRP participation in 2002. A general characterization of the participant population is provided below.

New York: Summer 2002 Experience

	Participants/ MW	Events	Load Curtailed	Payments
EDRP 2002	1711 1481 MW	22 hr Downstate 10 hr Upstate	~668 MW 34% of CBL (summer)	$3.3 mil
2001	292/712	23/17	425/38%	$4.2
DADRP 2002	24	1486 MWH scheduled	~14 MW (average)	$0.1
2001	16	2694	8	$.2

Fig. 1-3: Summer 2002 PRL Program Summary

As the adjacent figures show (Fig. 1-3 and Fig. 1-4), the demand response programs enjoyed increased participation over 2001, but DADRP continues to be very low, comparatively and nominally.[12] Participation in EDRP increased over five-fold, from just fewer than 300 in 2001 to over 1,600 in 2002.[13] Renewal rates that range between 58%-77% among the three programs are encouraging, as it indicates that customer expectations of program benefits are largely being met - an important

2002 Renewals

DADRP	EDRP	ICAP/SCR
77%	58%	69%

Fig. 1-4: 2002 Renewal Rates

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at the LBMP and then gets exactly that amount back. This provision makes the LSE neutral, at least with regard to DADRP bidding and to the LSE's subsequent market price exposure.

[11] In this discussion, EDRP refers to both customers enrolled in EDRP and those enrolled in both EDRP and ICAP/SCR.

[12] In this discussion, EDRP refers to customers enrolled in EDRP only and those enrolled in both EDRP and ICAP/SCR.

[13] Participation count excludes 20,000 residential customers that were subscribed and counted as an aggregation.

issue from marketers given the cost of acquiring participants. In addition, as customers become more experienced, the amount they curtail should increase and the hourly variance should drop, which improves the reliability, and therefore the value of these resources.

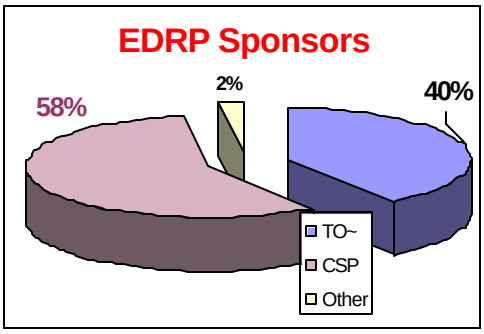


Fig. 1-5: EDRP Enrollment by Provider Type

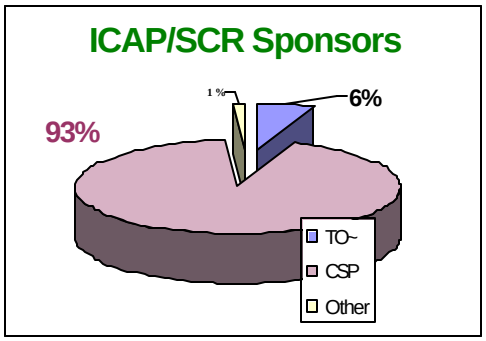


Fig. 1-6: ICAP/SCR Enrollment by Provider Type

Another positive trend is the increase in the number of CSPs marketing EDRP. They increased in number from 12 in 2001 to over 20 in 2002, accounted for 58% of the customers participating in the EDRP and provided 21% of the total MWH load reductions. The average EDRP hourly curtailment of 668 MW over the 10 event hours during the summer of 2002 is 50% higher than the corresponding value for 2001.[14] The EDRP payments were only about 27% higher in 2002, which reflects the lower number of event hours (12 versus 18 event hours state-wide in 2001, plus another 5 hours downstate).

EDRP overall curtailment performance in 2002 was higher than last year, but exhibited greater variability, as the figure shows. The increased level of joint EDRP and ICAP/SCR participation would be expected to reduce the EDRP portfolio variability. As the ICAP/SCR non-performance penalty acts as an incentive to achieve and maintain the full

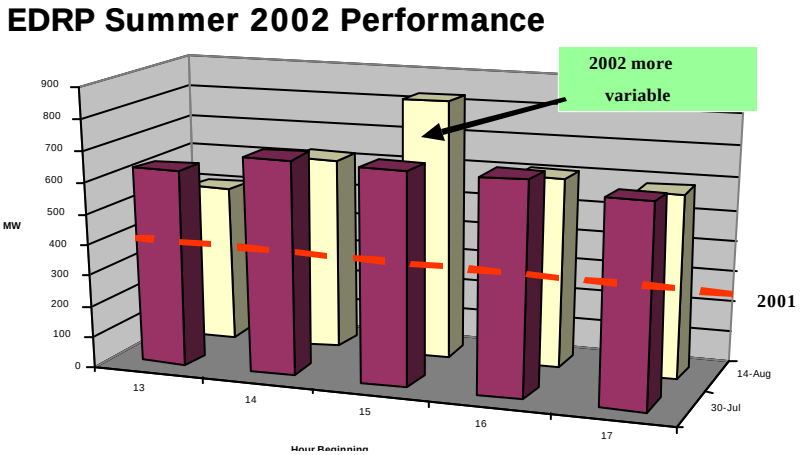


Fig. 1-7: EDRP Performance – Summer 2002

[14] Unless otherwise indicated, the 2002 values are for the two event days of the summer of 2002 that applied to all zones and all registered customers. EDRP was invoked on two April days for a total of 12

curtailment obligation, so too would the high level of renewals, help those customers with experience improve their performance. However, the smaller size of the new participants, combined with their inexperience, act as a counterforce pulling the average curtailment size down. The average participant load size dropped from just over 4 MW in 2001 to slightly less than 1 MW in 2002.

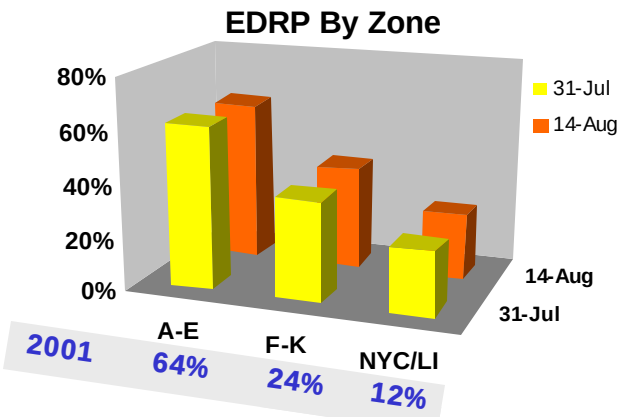


Fig. 1-8: EDRP Zonal Performance

In terms of achieving another important program objective, to increase participation in the downstate zones, the results are encouraging, but more improvement is still needed. EDRP curtailments in New York City and Long Island comprised about 20% of the state total, up from last year's 12%. EDRP curtailments in zones F-K, which is more constrained than their western counterpart zones, also increased as a percentage state-level curtailment. Still, given concerns about capacity shortage downstate in the next year or two, focusing on increasing participation and performance in those zones seems warranted.

Participants in EDRP are predominantly from the manufacturing and government and institutions sectors, with growing representation from the service sectors. A comparison of the distribution of participants and informed non-participants, as illustrated below, suggest that business activity, a key characteristic used by CSPs to promote and market EDRP cost-effectively, does little to

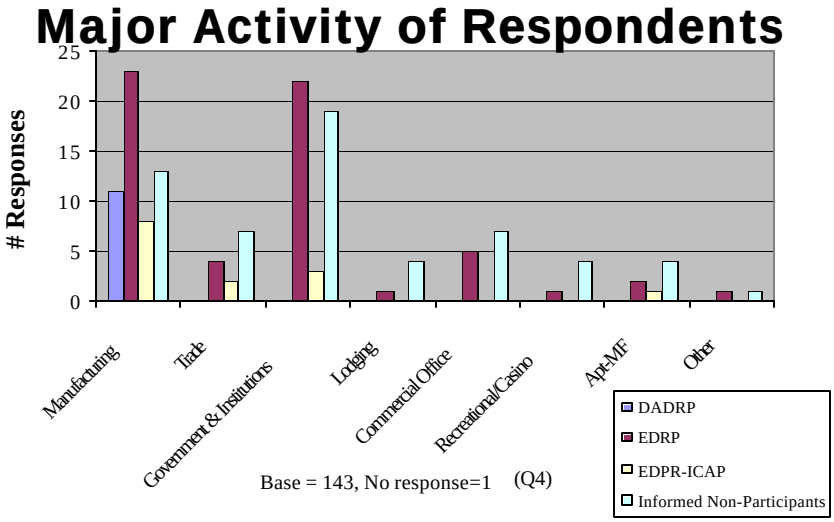


Fig. 1-9: Major Activities of Survey Respondents

hours in the downstate zones only and provided about 70 MW of load relief.

account for participation. DADRP participants are relatively larger customers involved in primary industries, like chemicals, wood products, and other manufacturing enterprises.

Customers who replied to our survey indicated that impediments to participation varied among customer types. While both commercial (80%) and institutional (55%) customers reported that occupant comfort was a primary impediment to shifting load, commercial enterprises face a loss of business if customers are uncomfortable. Concerns about production schedules were cited by 75% of industrial customers as the primary impediment to shifting load during summer peak days.

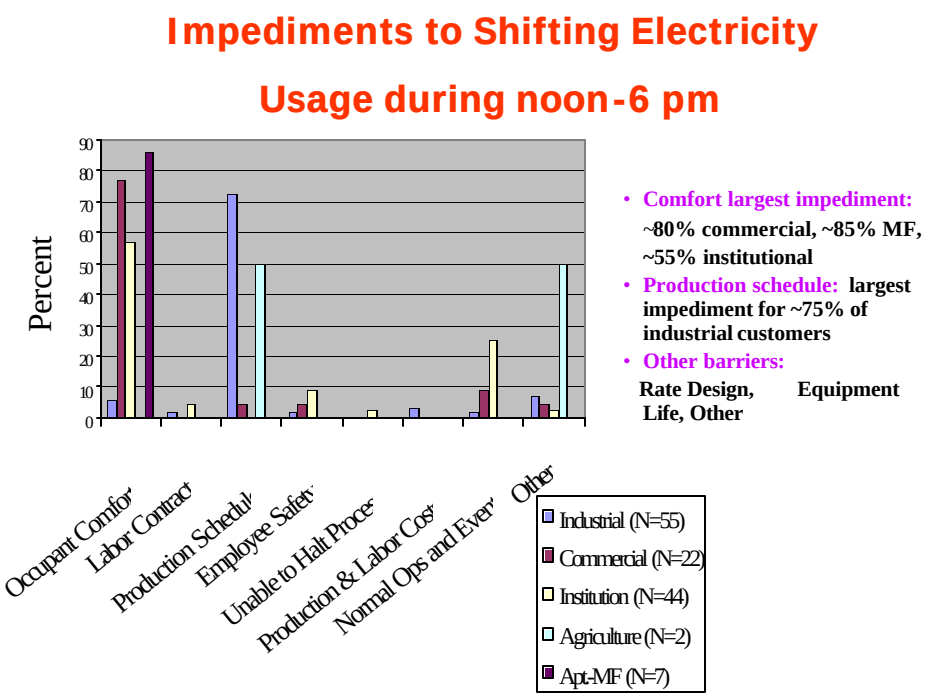


Fig. 1-10: Reported Impediments to Shifting Use

In the chapters that follow, the characteristics of participants and high performers are explored further using a variety of statistical and modeling techniques. The results reveal much about the barriers to participation that will be useful in expanding the current programs as they evolve to keep pace of the NYISO market operations.

Changes in PRL Programs for 2003

Several changes have been proposed, and are under review in the Price Responsive Load Working Group, for the 2003 PRL programs to improve performance and further integrate them into the NYISO's operations.

Demand Response Programs

In order to better integrate the demand response programs into NYISO operations, ICAP/SCR and EDRP could be sequentially dispatched based on need. System operators would determine if the level of reserves warrant using demand response to alleviate the condition. If so, the obliged ICAP/SCR resources would be called first and then EDRP resources would be dispatched only if they are needed.

The change from coincident to sequential dispatch of ICAP/SCR and EDRP would result in changes in two program provisions and would also impact how LBMPs are set when events are called, as follows:

- Separate ICAP/SCR and EDRP load nominations.

  Starting next year, customers would be required to nominate curtailable load to either ICAP/SCR or EDRP. Customers could offer load curtailments in both programs, but they would have to demonstrate that they have sufficient metering to distinguish between loads in ICAP/SCR and EDRP.

- New dispatch protocols

  When system operators determine that demand response resources should be dispatched, they would specify the level required on a zonal basis, and then proceed to dispatch the available resources beginning with ICAP/SCR. If the available zonal ICAP/SCR resource is less than what is needed, all available EDRP resources in the zone would be dispatched. If, instead, the ICAP/SCR resources exceed the amount of demand response needed, the system operator would determine which of the available ICAP/SCR resources to dispatch using a strike-price methodology. All ICAP/SCR resources would be arranged according to their strike price, from lowest to highest, and then dispatched starting from the lowest and continuing up the bid curve until the need is met. ICAP/SCR resources with strike prices above that of the last resource dispatched would not be required to curtail and would be deemed in compliance with their ICAP/SCR requirement for that event.

  ICAP/SCR resources that reduce load during a declared event would receive the prevailing LBMP, with a bid production cost guarantee. If the market LBMPs are below the customer's strike price, then the customer would be paid an additional amount to make up the difference. EDRP resources would continue to receive the higher of $500/MWH or prevailing LBMP when they curtail during a declared EDRP event.

- Impact on Real-Time market LBMPs

  Previously, ICAP/SCR and EDRP resources were not directly considered in setting LBMPs during periods when they were dispatched. It is proposed that starting in 2003, the price paid to these resources would be taken into account in setting prices utilizing a hybrid-pricing rule. In short, if the PRL resources that were dispatched displaced an available generation unit, in whole or in part, and as a result the LBMP fell, then the LBMP would be set at the level of the marginal PRL resource. In the case when only ICAP/SCR resources are dispatched, the PRL price that is considered would be that paid to the last, most expensive, resource dispatched. In the case when EDRP is also called, then the EDRP $500/MWH floor would be used.

PRL Energy Program

In order to promote greater participation in DADRP, two changes to the program have been proposed for 2003. First, the penalty provision for non-compliance may be lowered to fall more in line with the rules generators abide by in the Day-Ahead Market. Currently, customers that fail to curtail the amount scheduled pay 110% of the higher of the scheduled DAM LBMP or the real-time LBMP. Second, the NYISO has agreed to allow CSPs to offer DADRP services to any customer. Previously, only an LSE could sponsor DADRP participation. However, participating CSPs will be required to meet credit worthiness standards that will be established by the NYISO.

Report Overview

Chapter 2 describes the goals of the 2002 PRL program performance review, establishes a set of hypotheses about program performance that serve to direct the data gathering phase and the methods used to analyze this collected data. Chapter 3 describes the design and administration of the customer survey in greater detail. Chapter 4 reports the results of analyses directed at understanding why customers participate by identifying and characterizing barriers to participation. Chapter 5 summarizes how customers responded to curtailment events using a variety of measures of performance. Chapter 6 quantifies the level and flow of benefits arising from curtailments undertaken in the April and summer (July and August) 2002 EDRP events. Chapter 7 reports on a survey conducted with technology and commodity firms to ascertain their interest in becoming involved with offering PRL programs, with a focus on how NYSERDA PON programs can be most useful in attracting them into the market.

Chapter 2 - Evaluation Overview and Methods

Background

The New York Independent System Operator (NYISO) collaborated with wholesale electricity market stakeholders, including NYSERDA, in 2000-2001 to develop and implement emergency and economic demand response programs to access customers' abilities to shed load in response to high prices and/or situations where the reliability of the electricity grid might be jeopardized. NYSERDA participated in the NYISO working group that created these price responsive load (PRL) programs and developed complementary Enabling Technologies for Price Responsive Load Management and Peak Load Reduction programs to promote expanded participation.

During the Fall of 2001, an evaluation of the these programs, commissioned jointly by NYISO and NYSERDA, was conducted by Neenan Associates with support from the Consortium for Electric Reliability Technology Solutions (CERTS), particularly by staff from Lawrence Berkeley National Laboratory (LBNL) and Pacific Northwest National Laboratory (PNNL). The study included several components including surveys of customers, to improve the understanding of participant demographics, curtailment strategies and satisfaction with the programs, and an analysis of customer performance data to quantify benefits for participants and for the overall marketplace (e.g., price reductions, reliability enhancements, etc.).

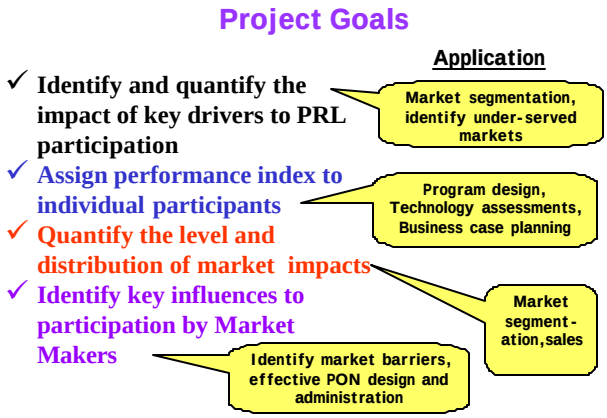


Fig. 2-1: Evaluation Project Goals

The feedback from this evaluation assisted NYISO and NYSERDA in: 1) quantifying the benefits of customer participation; 2) determining what aspects of the NYISO programs were attractive to customers and which ones needed to be modified; and 3) modifying NYSERDA program offerings to target lowering barriers to participation.

2002 NYISO PRL Evaluation

The NYISO's PRL programs were continued in 2002 and NYSERDA continued to provide funding for enabling technologies though Program Opportunity Notices (PONs). Consequently, these entities desired to extend the comprehensive evaluation of the previous year with two new areas of focus. First, the 2002 PRL program analysis focused on characterizing barriers to participation in DADRP. Although the number of subscribers to DADRP increased slightly, bid activity and the amount of scheduled curtailments was lower in 2002 than in 2001. Because day-ahead market participation is widely viewed as being a critical element of a robust electricity market, identifying barriers to participation in DADRP was deemed to be of the utmost importance for this year's evaluation. Accordingly, this year's survey and subsequent analyses were specifically designed to better characterize those barriers.

NYSERDA funding for 2001 and 2002 was focused on demonstrating the value of enabling technologies to customer PRL program participation, with the expectation that by doing so, firms that manufacture and sell such devices would be enticed into the market and assume the role of recruiting and servicing participants to PRL programs as a means of creating demand for their products. Moreover, commodity retailers and LSEs would use the available PON funds to create customer interest in switching from the default POLR service to their competitive offerings. Finally, PON funds were expected to increase market entry by specialized curtailment service providers (CSPs) seeking to develop a profitable portfolio of PRL resources.

The presence of diverse and committed market makers is an important element of developing the overall retail market structure. After two years of experience, NYSERDA desired to characterize the role its funding plays in how these businesses viewed PRL program participation as a business proposition. So, while last year's process analysis concentrated on how LSEs and CSPs viewed NYSERDA PON performance, with regard to meeting their immediate needs, this year's analyses focused on characterizing how PRL was viewed by existing and potential market makers as contributing to their long-run business goals and interests. Thus, a different survey and evaluation methodology were developed and implemented.

Project Team

The evaluation of 2002 PRL program performance was conducted by Neenan Associates and a team of researchers associated with the Consortium for Electricity Reliability Technology Solutions (CERTS).[1] NYISO and NYSERDA provided funding for Neenan Associates, which was responsible for project management and deliverables. Funding for the CERTS team was provided by the Department of Energy. The analysis involved almost a dozen researchers that contributed collectively over five man-years of effort.

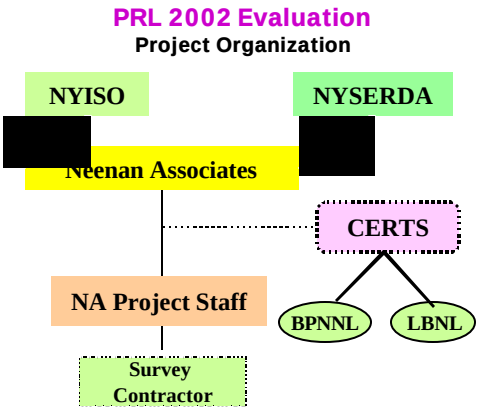


Fig. 2-2: Evaluation Project Organization

Approach

As was the case last year, the project team analyzed NYISO market data to quantify the actual MW reductions, the improvements in system reliability and the impacts on electricity prices. The contribution of NYSERDA PON participants was derived from these overall PRL program benefits. In addition, a survey of program participants and non-participants was implemented to: 1) characterize customer preference for various PRL programs; 2) assess customer familiarity with NYSERDA programs and whether/why they chose to participate or not participate in them; 3) determine the important correlations among customer characteristics (e.g., sector, size, load curtailment strategy) and PON participation; 4) determine the level of satisfaction with PON and PRL program features and obtain recommendations for improvement; and 5) evaluate customer needs and payback expectations regarding enabling technologies.

The instrument developed last year served as the basis for this year's survey, but some important modifications were made to accommodate this year's special focus on DADRP. As a result, the survey administration process differed from that of 2001 whereby surveys were mailed to customers, 111 of which filled them out and returned them to Neenan. This year's survey was administered to 144 customers directly by means of a telephone interview, two-thirds of which

[1] The CERTS researchers are associated with Lawrence Berkeley National Laboratory and Pacific Northwest National Laboratory.

were conducted by a vendor, and one-third by the CERTS team research scientists. Like last year, several prizes were awarded by a lottery, as an inducement to participate in the survey.

To guide the survey design and evaluation effort, a set of hypotheses was constructed to reflect the issues that NYISO, NYSERDA, and other stakeholders identified as requiring more information before much needed resolution could be achieved. Based on discussions with the NYISO and NYSERDA and others, such as the NYSDPS, end-use customers and customer representatives, the project team drafted a set of issues and corresponding hypotheses that were then circulated for review.

These hypotheses then served as the foundation for the survey design and subsequent analyses. The hypotheses were constructed as testable propositions. Each posed a question, the answer to which could be construed as affirming the proposition, or lending doubt as to its validity, using accepted statistical methods. To ensure that the results of the analysis of these propositions contributed to issue resolution, the propositions were constructed to minimize Type I errors (accepting that the proposition was true, when in fact the survey results did not support such a conclusion). An example is provided below.

H_o: Particularly "comfort-sensitive" customers are less likely to participate in PRL programs than other customers

H_a: Comfort sensitive customers participate at the same rate, which implies that the program design is not biased against such customers

Two survey versions were developed to test, in part, these hypotheses. First; a base survey that would be administered to customers by a vendor via scheduled telephone interviews about 20 minutes in length was created. The time constraint limited the breadth of questions that could be asked and dictated that most responses had to be closed ended (respondents chose from an established list of alternatives). This base survey then became the foundation for developing a second instrument, called the PRL audit.

This enhanced survey was designed to be administered by experienced engineers, which allowed greater latitude in recording customers' responses to the questions asked. By probing issues with respondents, the interviewer would be able to record subtle but important nuances that distinguish customers and contribute to explaining behavior. In addition, the PRL audit, which required forty-five minutes to complete, included additional inquiries. The genesis of the PRL audit was research conducted by the CERTS team last year, when they developed and field tested

protocols for gathering extensive data on customers' equipment inventory, characteristics, and usage that would help resolve many issues related to why customers are reluctant to participate, or participate in only a limited fashion in PRL programs, despite an apparent larger capability.

The base survey instrument was designed in three stages. In the first, a base rate and rank instrument was developed using many of last year's questions to develop a longitudinal database on preferences and customer characteristics. New sections were added to address the focus on DADRP and to explore customer preferences for alternative bidding methods, using the hypotheses as the foundation for what questions to ask. Finally, structural changes were made to the instrument to accommodate the direct administration of the survey by a vendor.

Subsequently, an alternative instrument was developed in which the research team identified areas in the base survey where, due to ambiguity about customer circumstances or narrow interpretations of wording, the questions explored only the surface of a deeper issue. The CERTS staff then developed more, in depth probing protocols and a complete PRL audit was prepared, and reviewed.

The data for the surveys described above can be used to evaluate customers' revealed preferences. Each was confronted with a decision to participate or not, and the data collected can be used be used to characterize what factors were most important in the decisions. However, the results are only applicable to situations where the exact same programs are offered. They do not provide insight into the response to different program configurations.

A set of conjoint-type questions was added to both surveys. Respondents were asked to make 20 separate choice decisions. In each, they were offered alternative program designs each described by a specific but different level of five feature characteristics (event notice, event duration, curtailment benefit level, noncompliance penalty level, and start time). The responses to these questions provide the data needed to develop a stated preference choice model that associates customers' likeliness to participate with program features.

Customer Categorization/Segmentation

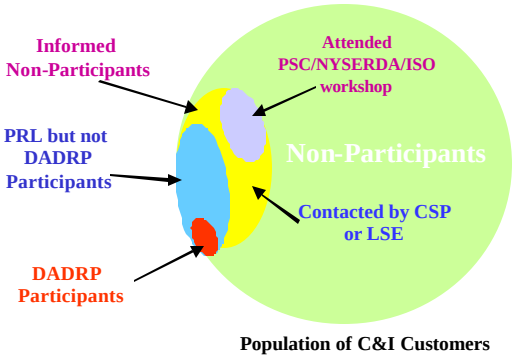


Fig. 2-3: Customer Segmentation

Survey Administration

The research team tested the base survey and the PRL audit instruments with selected customers. Based on the results, refinements were made to adjust the wording to better fit customers' perspectives, and length of the instrument was adjusted to fit the target completion time.

The base survey was administered to participants and non-participants by a survey vendor during September and early October. The CERTS teams conducted the PRL audits in the same period. Four sample frames were constructed. Three were compiled from NYISO subscription records that contain the names of all PRL program participants, which were sorted into three categories: those that participated in DADRP, those that participated in EDRP only, and those that participated in EDRP and ICAP/SCR. (Customers that participated only in ICAP/SCR were not included in this analysis.) The three categories constructed are not exclusive since all DADRP participants also participated in EDRP and some in ICAP/SCR. However, because of the focus this year on barriers to DADRP participation, this partition was necessary to ensure that the questions on the survey were properly addressed.

The fourth sample frame was constructed to represent non-participants, customers that did not join the program this summer. It was comprised of customers that attended one of six briefings on PRL programs conducted around the state in April and May by NYSERDA, NYSDPS, and NYISO. The workshop introduced customers to the programs, demonstrated how program provisions worked and provided examples of the potential benefits of participation.

Over 300 customers attended a workshop, about one-quarter of which (75) joined one or more PRL programs in 2002. The remaining customers constitute a subpopulation of informed non-participants (INP), customers that were provided with extensive information about the programs, but elected not to participate in 2002. Last year, the INP sample frame was constructed from names and addresses provided by LSEs of customers that they had contacted about program participation. The means by which customers were contacted varied widely, from participation in a workshop to receiving a letter or bill stuffer announcing the program, which provided insight into the value of information to the decision to participate of not. But, the lists were not representative of the population in general, so extrapolation of the results was difficult.

Because this year's survey was conducted through a telephone interview, telephone contact information was required for all customers in the INP sample frame. This requirement

made compiling the sample frame from LSE and CSP contact lists impractical. Instead, the population of workshop attendees was used to represent non-participants, albeit they likely do not represent the population of all customers. LSEs and CSPs used these workshops as a means of informing their customers of the programs, and they likely were biased toward larger customers or customers with which they have established a relationship that goes beyond the usual communication of information. Second, customers that attended are likely those that either had previous experience with a similar program, have or are considering the installation of enabling technologies, or have usage patterns conducive to PRL program participation. The survey results are described in Chapter 3.

Data Sources and Uses

Data used in the analysis consisted of secondary data acquired from NYISO, and primary data collected directly from customers via surveys administered by the project team. Secondary sources of collected data are illustrated in the table below and include the following:

Project Database Elements, Sources, and Uses		
Input	Import or manual data entry (some range checking)	
Retrieval	Queries for counts and reports	
Data Elements	**Source**	**Use**
Participant subscription information	NYISO registration forms	Sampling frame for participant survey administration
Non-participant information	PSC and CSP sponsored workshop lists	Sampling frame for participant survey administration
CSP and host utility information	NYISO CSP list	Participation analysis
Event and performance data (computed)	NYISO	Analysis of event performance
Survey administration data	Neenan	Track survey administration (unique ID, mail merges, sent & reply dates, etc.)
Survey response data	Survey instruments	Report and evaluate end-use response to participation, response and program features
Other end-use firm related data	Survey instruments and/or follow-up interviews	Additional data for elasticity analysis and participant segmentation

Table 2-1: Project Data Requirements

- Program subscription and performance data bases
- NYISO hourly prices (LBMPs) and load
- Customer Survey - a survey developed and administered to PRL program participants and other customers for the purposes of characterizing their satisfaction with the programs and collecting data that can be used to quantify how program features contribute to their willingness to participate and respond to curtailment events.

- PRL Audits – a more detailed, complex, and adaptive survey instrument completed by a randomly selected group of participants. It includes a detailed equipment inventory representing the participant's load management capability, and information about the firm's operation and objectives.

Evaluation Plan

A careful analysis of the responses to the 2002 customer acceptance survey will help answer a number of key questions about participation, performance, and customer acceptance of the NYISO Demand Response Programs. Answers to these questions are of particular interest to the NYISO, NYSERDA and DOE, the project funders, to the NYSDPS, in order to craft public policy, and CSPs seeking to operate successful retail PRL programs. Moreover, these findings also have implications for the design of and participation in similar programs that might be implemented elsewhere in the country as part of FERC's standard market design.

Much of the initial analysis of these survey results will focus on differences between informed non-participants and on participants in EDRP and/or ICAP/SCR. There is keen interest in knowing more about participants in DADRP, but there are still only a small number of them. Some analysis can be attempted with these customers as part of a general analysis plan, but much of what we learn about customers in DADRP will be gained through the extended analysis of the data collected through the PRL audits.

As with the 2001 evaluation, one of the primary objectives of this year's PRL evaluation will be to better understand customers' decisions regarding participation in the NYISO's several demand response programs. It is perhaps convenient to think of these decisions as falling into four groups. We would like to use these data to better understand customers':

- Current Participation Decisions
- Continued or Future Participation Decision
- Load Reduction Subscription Rates
- Actual Event Performance.

Current participation decisions include those by informed non-participants not to enroll in any program and program participants that have elected to enroll in one or more of the NYISO's three programs: ICAP/SCR, EDRP, and DADRP. Despite the substantial increase in enrollment

this year in ICAP/SCR and EDRP, it is still critical to gain a better understanding of what motivates the decision to enroll in a PRL program. Furthermore, these programs are new, and continue to evolve; we must know which customers would continue in the programs if critical program features were changed.

Subscription rates indicate the load customers initially plan to curtail during an emergency event, or, in the case of DADRP, in real-time, if their bids were accepted in the DAM. If a customer belongs to both EDRP and ICAP/SCR, participation levels may differ by program, reflecting the different performance requirements and measurements.

Clearly, these decisions about program participation and performance are jointly determined by the characteristics of customers (e.g. type of business, number of hours open, number of production shifts, peak time of electricity use, etc.), the particular features of the various programs, and perhaps, even by conditions in the market (e.g. expectations about the level of wholesale prices in the DAM or in the RTM, etc.). Factors affecting decisions by new participants in 2002 may differ from those firms also in the programs during 2001. Financial assistance from NYSERDA or others in purchasing or installing load management equipment is hypothesized to influence decisions, as could past experience with load management programs and the usefulness of information received about the current programs. We gain important insights into how these factors interact to influence the customers' decisions through two levels of analysis.

Top Level Analysis

The first, top-level analysis involved a careful examination of the survey raw data and the construction of some basic frequency tables, summary statistics, and cross tabulations. No analysis should proceed without a solid understanding of these data. In this "top" level analysis, much can also be learned about these important decisions through some straightforward hypothesis tests about differences in the means of key measures of satisfaction or preference between important subgroups of the survey respondents.

Attendance Status	*Participation Status* Participated	Did Not Participate
Attended	40	10
Did Not Attend	25	25

Table 2-2: Participation in NYSERDA/PSC Workshop

The hypotheses constructed to guide the analyses were evaluated using chi-square tests for independence of table rows and columns. For example, in the (hypothetical) cross-tab shown, 80% of those who attended (a briefing) participated (in a PRL program), while only 50% of non-attendees participated. The chi-square procedure is used to determine the likelihood that the two dissimilar rows could in fact be samples from the same population (i.e. with the same underlying probability of participation). If this probability is sufficiently small (5% is a common threshold), the (null) hypothesis that they are from the same population is rejected, in favor of the hypothesis that the rows represent different populations. For the values in the example, the likelihood that two such different proportions would result from random samples of the same population is less than 0.2%. The null hypothesis would be rejected in favor of the hypothesis that briefing attendance is significantly associated with participation.

Comprehensive Analysis

Informative as these simple hypothesis tests can be individually, however, they do not account for other factors that might be related to the differences that led to rejecting or failing to reject some of the hypothesis tests. In more in-depth analyses, we attempt to control for these other factors by constructing theoretically consistent behavioral models and applying more extensive multiple regression analysis. The details of the evaluation methods associated with these extended analyses are discussed below.

Evaluation Methods

Choice modeling – Two different choice modeling activities can be performed using the collected survey responses. First, conjoint survey questions asked customers to choose between alternatives with different features. By imposing behavioral assumptions (consistent with economists' notion of demand) on conjoint data to characterize customers' decision-making behavior, this choice model utilizes econometric techniques to quantify the relative contribution of individual features to the value the customer realizes from participation, the results of which are interpreted as the impact of features on the likelihood of program participation. Once fully configured, the choice model supports the evaluation of alternative program designs, represented by alternative feature levels, on expected participation, which is useful for both program design and modeling expected participation and price response.

A second choice model can be developed to explain firm's current PRL program participation decision. Self-reported firm characteristics and actions taken by New York State agencies, market participants, and other institutions are used as predictors in assessing the likelihood of a customer's choice to join an emergency program (EDRP and/or ICAP/SCR), the day-ahead program (DADRP), or no PRL program whatsoever. Such a model provides important insight into the kind of customers who are likely to join a PRL program.

Models for Evaluating Customer Satisfaction and Price Responsiveness

Satisfaction	Customer solicited ratings and rankings
Arc Elasticity	Measures participant's average performance over all events. No other explanatory factors included.
Demand Elasticity	Full behavioral specification of demand that accounts for price and non-price factors that effect usage
Choice Model (1)	Uses stated preferences for alternative program designs to evaluate how customers value program features
Choice Model (2)	Uses self-reported firm characteristics to indicate customer participation in current PRL programs

Fig. 2-4: Evaluation Models

Market price simulation utilizes a statistical representation, developed from historical data, of how supply conditions influence market-clearing prices to estimate what the prices would have been if the PRL curtailments had not materialized. This method is easier to apply, but its accuracy depends upon the degree to which a statistical model can capture the peculiarities of market pricing that led to extreme prices, and the ready availability of market characteristic data such as constraints and generation availability.

Price Elasticity: Two different measures of elasticity are of interest:

The **own-price elasticity** measures how consumption of electricity varies with respect to the price paid for electricity. Generally, data over an extended period of time where the price of electricity varied are required to estimate this elasticity, although if electricity consumption is considered to be truly discretionary, e.g., foregoing air conditioning for a few hours, then PRL curtailments are consistent with this measure of price responsiveness.

The **substitution elasticity** measures how firms facing time-varying electricity prices alter their usage to shift electricity from the higher priced periods to other times, which is the case for PRL load curtailment situation where customers do not forego usage altogether, but instead re-adjust the timing of its consumption.

Elasticities can be measured simply, using the arc elasticity method, or derived from a complete representation of the customer's demand of electricity. The more simple arc elasticities are derived from event performance, calculated as the change in the customers' usage, relative to the CBL, during the event divided by the change in price, measured as the difference between the PRL price, either explicit or implicit, and the basic tariff or contract price the customers would normally pay. The data needed for such calculations are readily available.

Estimating fully specified demand equations and deriving the substitution elasticity can produce a more insightful representation of response. The substitution elasticity measures a customer's ability and willingness to produce outputs using different levels of inputs, which characterizes the underlying production of service process in a physical sense. The substitution of interest here is between electricity at times of high prices (during events) and other times when prices are lower. The higher the substitution elasticity, the more price responsive the customers. Estimating substitution elasticities for individual customers requires interval data for the entire period during which the customer participates in the program (usually the summer months) along with weather data and firm characteristics (operating or output measures, labor schedules, etc.) necessary to account for factors other than price that influence changes in load from hour to hour.

Other Performance Indicators that provide insight into the character of customer participation and curtailments include:

- Curtailment performance relative to subscription measures how well customers estimated their ability to respond when they registered for the program. Higher performance by this metric (under equivalent price incentives and penalties) indicates that the participant understands its capabilities well, and therefore will performs more uniformly over all events. Low performance variance is useful to system dispatchers when they consider deploying the available resources, and want to predict the outcome as precisely as possible.
- Curtailment performance relative to CBL measures what proportion of the current level of usage the customer curtails when an event is called. Higher performance by this measure is valuable as it lowers resource acquisition and transactions cost per delivered kWh of curtailed load.

Methods Employed

The analyses conducted are summarized in the table below and described in more detail in the chapters that follow.

Table 2-3: Summary of Evaluation Methods and Data Requirements

Method	**Description**	**Data Requirements**
Top End Analysis	**Use statistical tests to evaluate rate and rank survey responses and test hypotheses.**	**Survey responses for both Base survey and PRL audit**
Curtailment responsiveness	**Characterize individual and group response to events**	
Arc demand elasticities	**Price-weighted simple price elasticities**	**Event CBL and curtailments, and base service electricity rate**
Performance Indices	**Metrics based on relative measures of load curtailment capability**	**Event CBL and curtailments**
Behavior Modeling	**Characterize how observable customer characteristics survey responses contribute to the decision to participate**	
Revealed Preferences	**Define characteristics and factors that explain why customers chose to participate or not**	**Responses to rate and rank survey questions, and customer characteristics.**
Stated Preferences	**Use customer choices in hypothetical decision situations to deduce the value of product characteristics to likelihood of participation.**	**Responses to conjoin survey questions and customer characteristics.**
Market Impacts	**How curtailments effected market prices**	**Hourly LBMPS and corresponding loads for the DA and RT markets, by zone, and other market condition information such as available generation and transmission node constraints.**
Reliability Benefits	**The value of curtailments in preventing forced outages**	
Collateral Benefits	**How price changes are transformed into lower purchase costs to consumers.**	

Chapter 3 – End User Survey

Survey Goals and Design

A two-part survey was administered to NYISO program participants and informed non-participants (INP) to identify and quantify the impact of key drivers to price-responsive load (PRL) participation, and to assess technology installed to facilitate demand response. Informed non-participants are end users who attended demand response informational seminars conducted by the New York State Department of Public Service (NYDPS) and NYSERDA around New York State in the spring of 2002, but who did not register to participate in any NYISO demand response program.

The focus of this year's end user survey was to identify barriers to DADRP participation and to test response to proposed program changes. Part 1, Customer Acceptance Survey, contained targeted questions based on the end users' NYISO PRL program registration type. The Customer Acceptance Survey included a series of questions on end user characteristics (firmographics), possible response strategies, the value of information from various workshops and program marketing materials, factors influencing their decision to not participate in other NYISO PRL programs, barriers to customer participation in the DADRP, and the impact of various proposed changes in NYISO program rules on their future program participation. In addition, select questions from the 2001 NYISO PRL survey were repeated in order to facilitate analysis of time trends among program participants. Part 2, a conjoint survey, tested end users' attitudes toward various sets of program features to establish which features customers prefer. Complete versions of Part 1, the Customer Acceptance Survey and Part 2, the Conjoint Survey, are included in Appendices 3A and 3B, respectively.

As part of its research for the U.S. Department of Energy, the CERTS team participated in the design and administration of the 2002 NYISO Customer Acceptance survey, which included developing an in-depth version of the survey called the PRL Audit. This extended and more detailed version of Part 1 was administered to a subset of end users by a CERTS staff engineer who attempted to illicit more open-ended responses.

Sampling Frame

NYISO Program Participation

The Emergency Demand Response Program (EDRP) and Installed Capacity-Special Case Resource Program (ICAP/SCR) had significant increases in registered participants in 2002 compared to 2001 program registrations (543% and 20%, respectively). Overall retention in 2002 NYISO programs was high among 2001 program participants: 77% for DADRP, 58% for EDRP and 69% for ICAP/SCR (Fig. 3-1).

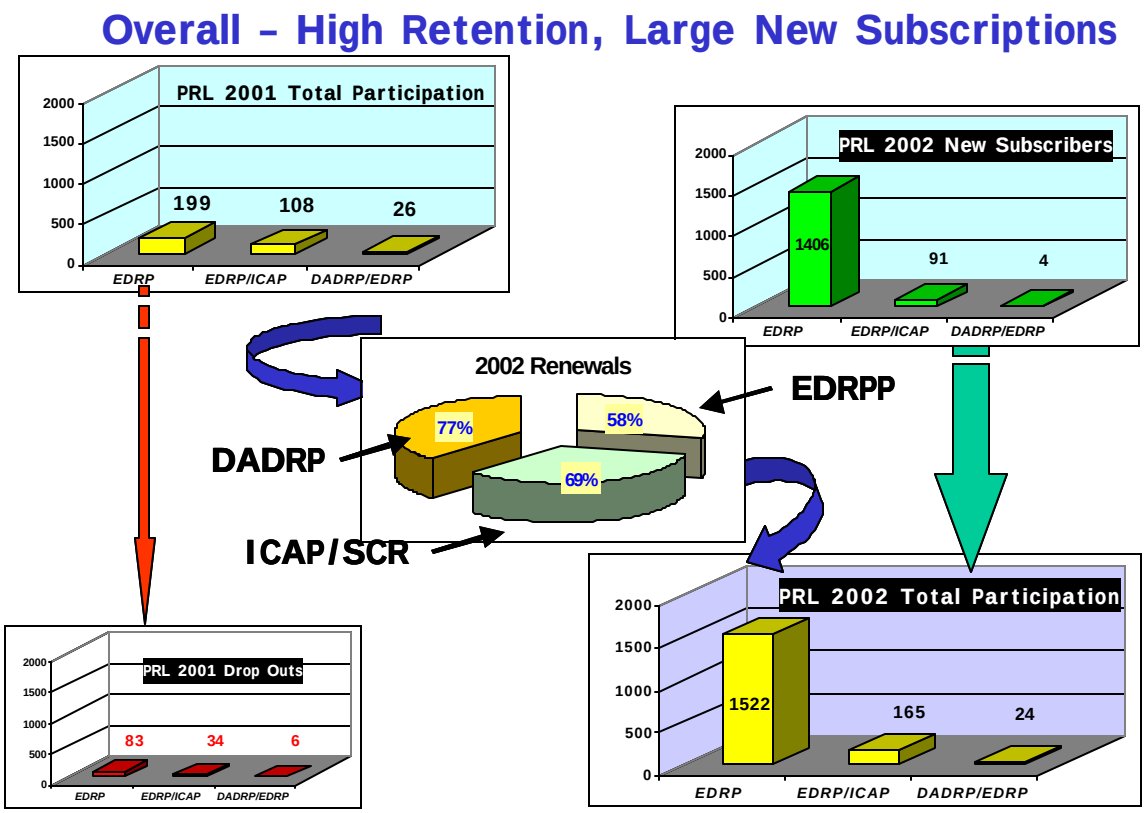


Fig. 3-1: Subscription Rates for NYISO's PRL Programs

Table 3-1 illustrates the number of individual participants, by provider type, in each of the three NYISO PRL programs: EDRP, DADRP, and ICAP/SCR, as well as the informed non-participant population available for the survey. In Table 3-1, TOs, Transmission Owners, include six regulated utilities and two power authorities, New York Power Authority and Long Island Power Authority. CSPs, Curtailment Service Providers, include competitive load-serving entities

(LSEs) and load aggregators, while the "Other" category includes customers directly served by NYISO and Limited Customers, customers who have registered directly with NYISO for participation in the price-responsive load programs.

Table 3-1: NYISO PRL Program Population

					Totals			
	TOs	CSPs	Other	Total	Single Site Participants	Multi-Site Participants~	Informed Non-Participants	Total
Available Population by Program								
EDRP	1238	456	17	1711	1279	432		**1711**
DADRP	15	3	6	24	19	5		**24**
ICAP	14	234	3	251	162	89		**251**
Informed Non-Participants			324	324			324	**324**
Subtotal	***1267***	***693***	***350***	***2310***	***1460***	***526***	***324***	***2310***

The program participants were further classified by whether they were a single site participant or multi-site participant. Multi-site participants are individually registered locations of an entity with a single point of contact for energy management decisions, such as a school district, franchise, supermarket chain or big-box retailer. Multi-site entities have as few as two participants to as many as 50 sites registered. In 2002, 89 multi-site entities represent approximately 25% of EDRP participants, compared to less than 10% of participants in 2001. In addition, about half of the ICAP/SCR participants were multi-site registrations.

In 2002, a pilot for small load aggregations was introduced to permit end-users without interval meters, primarily residential, to participate in EDRP through a load aggregator. The baseline for determining performance was computed using a sampling methodology approved by NYISO in advance of participation in any event. Two small load aggregation pilots of less than 25MW each account for 19,226 additional participants in EDRP this year.

Survey Groups

The available population was segmented into four survey groups:

1) Informed non-participants;
2) DADRP – participants who were registered in DADRP and any other NYISO program;
3) EDRP and ICAP/SCR – participants who were registered in EDRP and ICAP/SCR, but not DADRP; and
4) EDRP only.

For ease of survey administration, each NYISO program group was further sub-divided into single site and multi-site lists to ensure that only one survey was issued to the appropriate multi-site contact.

Two groups of individually registered participants, totaling 1002, were omitted from the survey samples: NYPA participants and LIPA participants. In addition, the small load aggregation pilot participants were not surveyed. These participants were not included in the surveys conducted by Neenan Associates on behalf of NYISO and NYSERDA because their program sponsors conducted independent evaluations.

Survey lists for the PRL Audit were generated first because the interview process was expected to take longer than the base telephone survey. The PRL Audit focused primarily on barriers to participation in DADRP among currently registered NYISO program participants, so no informed non-participants were included in the extensive survey. The lists drawn for the PRL Audit included all DADRP participants, and randomly selected lists of EDRP/ICAP and EDRP only participants. Multi-site participants accounted for about one-third to one-half of each of the randomly generated survey lists.

For the base survey, the survey vendor was provided with all remaining names in the EDRP/ICAP and EDRP only groups, plus the entire list of informed non-participants.

Survey Administration

A survey vendor working as a sub-contractor to Neenan Associates was the initial contact point for survey administration. For the base survey, the survey vendor contacted customers drawn from the sampling frame and conducted a telephone interview at that time or set an appointment to call the customer back. In addition, for customers in the sampling frame that were targeted for the PRL Audit, the survey vendor established appointment times for the CERTS engineers to conduct interviews.

For PRL Audit respondents, the survey process involved both completing a written survey form and a telephone interview. A CERTS engineer contacted the potential respondent, sent a survey form via e-mail and confirmed the appointment. The customer completed the form and returned it via e-mail for the CERTS engineer to review. At the scheduled time, the CERTS engineer called the customer to discuss their responses.

The conjoint survey, Part 2, was faxed by the survey vendor to customers who either set up an appointment for the PRL Audit, or who agreed to respond to the base survey. Customers returned the conjoint portion via fax directly to the survey vendor, who coded the responses.

Daily e-mail reports from the survey vendor provided updates to Neenan Associates on survey response progress. In addition, the survey vendor provided mail fulfillment services to send out reminder postcards to respondents who had completed Part 1.

Table 3-2: 2002 Survey Responses

					Totals			
	TOs	CSPs	Other	Total	Single Site Participants	Multi-Site Participants~	Informed Non-Participants	Total
Available Population by Program								
EDRP	1238	456	17	1711	1279	432		**1711**
DADRP	15	3	6	24	19	5		**24**
ICAP	14	234	3	251	162	89		**251**
Informed Non-Participants			324	324			324	**324**
Subtotal	***1267***	***693***	***350***	***2310***	***1460***	***526***	***324***	***2310***
Survey Lists					**458**	**89**	**290**	**837**
Survey Responses					**62**	**23**	**59**	**144**
						(represents 106 participants)		
Response Rate					13.5%	20.2%	20.3%	**17.2%**

Survey Response Rates

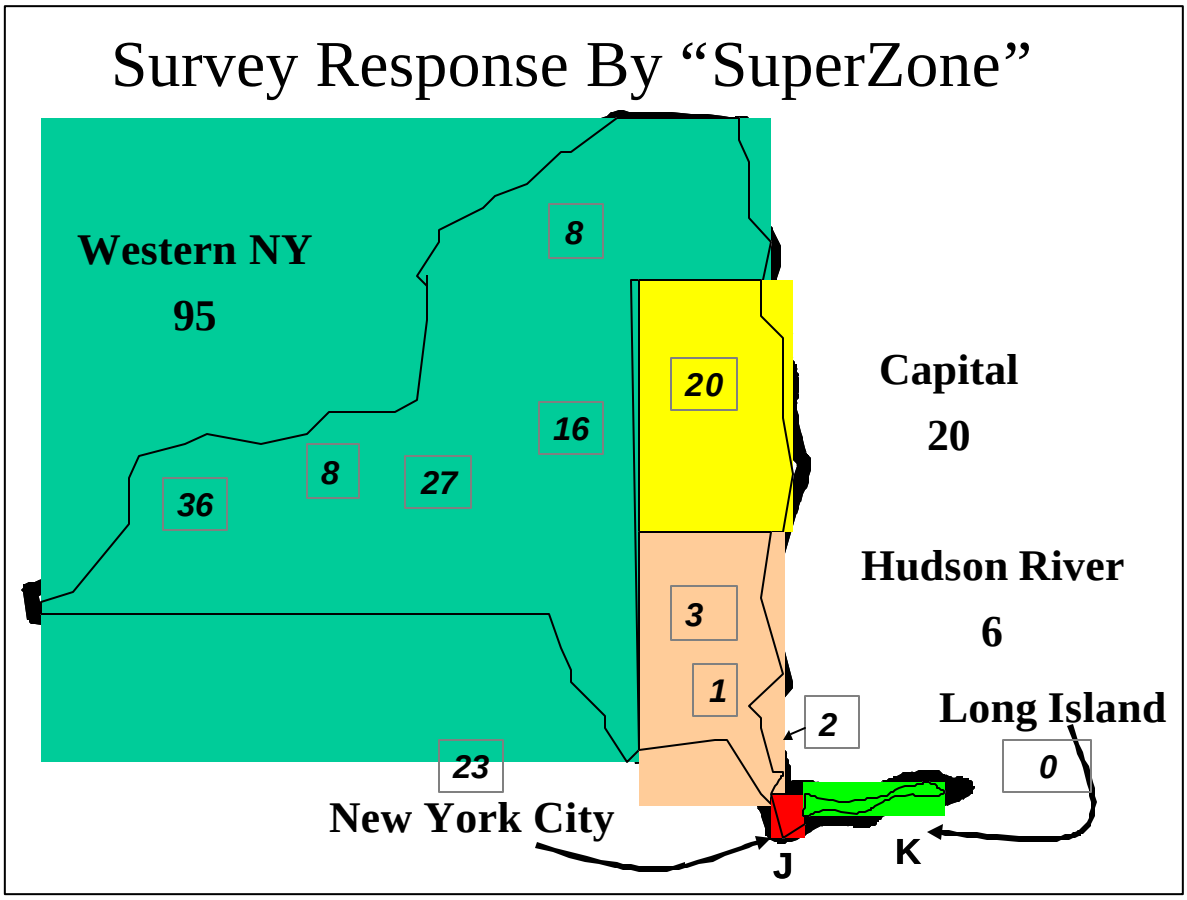
In total, 144 survey responses were received, representing a 17.2% response rate overall: 108 base surveys and 35 PRL Audits (Table 3-2). Of the 35 PRL Audit respondents, 11 were DADRP, 19 were EDRP only and 5 participated in both EDRP and ICAP/SCR. Approximately 20% of the multi-site entities, representing 106 participants, and 20% of the informed non-participants were among the survey respondents.

Table 3-3 shows the distribution of responses by survey group and participants who received NYSERDA funding through either the Enabling Technology or Peak Load Reduction PONs. Distribution of survey response by NYISO price zone and "superzone" is illustrated in the map below (Fig. 3-2).

Table 3-3: Survey Responses by NYSERDA Status

	NYSERDA funded	Non-NYSERDA	Total
Informed Non-Participants	1	58	**59**
DADRP	4	7	**11**
EDRP and ICAP/SCR	4	12	**16**
EDRP only	28	30	**58**
Total	**37**	**107**	**144**

Fig. 3-2: Survey Response by "Superzone"



Appendix 3A

Survey Part 1: Customer Acceptance Survey

This appendix contains the master list of questions used in the 2002 Customer Acceptance Survey. Sections represent groups of questions that were asked of respondents, based on participation criteria. The format of the Customer Acceptance Survey shown here does not represent the survey format administered to customers; it was administered by telephone.

2002 Electricity Demand Response Programs

Customer Acceptance Survey

Part 1: Customer Information

Section A: General

1. We want to verify some contact information we have for you to ensure that we are talking to the proper individual at your firm responsible for your facility's response to load curtailments and demand reductions.

*1.Name:*_____ *2.Organization:* _____

*3.Address:*_____

*4.Phone:*_____ *5.Fax:* _____

6.E-mail: _____

2002 NYISO PRL Evaluation

We are going to ask you a series of questions concerning your business and the ways in which you make investment decisions. Since it is possible that your firm has several facilities or locations across the state or possibly across the country, we would like you to answer these questions specifically for the location you have just given us.

2. What is your position/title in the organization?

- ❑ 1. FACILITY MANAGER
- ❑ 2. ENERGY MANAGER
- ❑ 3. GENERAL MANAGER OF YOUR ORGANIZATION
- ❑ 4. CEO/CFO
- ❑ 5. VP OF _____
- ❑ 6. OTHER (PLEASE SPECIFY) _____

3. Are you, or do you have an employee responsible for procuring and managing energy?

- ❑ 1. YES

  1.1 Proportion of time spent on these tasks: _____%

- ❑ 2. NO

4. What is the major business or institutional activity of your organization? (CHECK ONLY ONE)

- ❑ 1. HEAVY MANUFACTURING
- ❑ 2. LIGHT MANUFACTURING
- ❑ 3. WHOLESALE TRADE

- ❑ 4. RETAIL TRADE
- ❑ 5. GOVERNMENT
  - ❑ 5.1 Military
  - ❑ 5.2 Office buildings
  - ❑ 5.3 Water utility (water, waste water)
- ❑ 6. EDUCATION
  - ❑ 6.1 PRIMARY
  - ❑ 6.2 SECONDARY
  - ❑ 6.3 HIGHER EDUCATION
- ❑ 7. HEALTH SERVICES
  - ❑ 7.1 HOSPITAL
  - ❑ 7.2 CLINIC
  - ❑ 7.3 MEDICAL OFFICE
  - ❑ 7.4 RETIREMENT/EXTENDED CARE FACILITY
- ❑ 8. LODGING
  - ❑ 8.1 HOTEL
  - ❑ 8.2 MOTEL
  - ❑ 8.3 INN/CABINS/B&B
- ❑ 9. AGRICULTURE
  - ❑ 9.1 DAIRY
  - ❑ 9.2 OTHER LIVESTOCK
  - ❑ 9.3 CASH CROP
  - ❑ 9.4 SPECIALTY CROP
- ❑ 10. COMMERCIAL OFFICE BUILDINGS
- ❑ 11. RESTAURANT

- ❑ 12. RECREATIONAL, CASINO
- ❑ 13. APARTMENT/CO-OP/CONDOMINIUM BUILDING
- ❑ 14. OTHER _____

5. Could you please list your firm's most important products or services produced at your facility.

   1 _____

   2 _____

   3 _____

6. If you know your firm's 4-Digit SIC or NAIC code, could tell me what it is? (If they don't know 4-Digit, ask for 2- or 3-Digit SIC or NAIC)

   1. _____ (SIC) 2. _____ (NAIC)

7. On an average weekday, how many hours is your organization open for conducting business at this facility?

   _____ HOURS

8. Over a 24-hour period, approximately how many production shifts do you operate?

   _____ # OF SHIFTS

9. Approximately how many full-time employees or full-time equivalents does your organization have at this facility?

_____ # OF FULL-TIME EMPLOYEES OR FULL-TIME EQUIVALENTS

Section B: EDRP/ICAP SCR/DADRP Participants

10. Approximately how large are the facilities you have registered for the programs?

- ❑ 1. UNDER 15,000 SQ. FEET.
- ❑ 2. 15,000 TO 44,999 SQ. FEET
- ❑ 3. 50,000 TO 99,999 SQ. FEET
- ❑ 4. 100,000 TO 249,999 SQ. FEET
- ❑ 5. 250,000 TO 499,000 SQ. FEET
- ❑ 6. 500,000 TO 1 MILL. SQ. FEET.
- ❑ 7. 1 MILL. SQ. FEET OR MORE

11. How many buildings are included in the load reduction your firm registered in the programs?

Specify number : _____

Section C: EDRP/ICAP SCR/DADRP Non-Participants

12. Approximately how large are your facilities here in New York State?

- ❑ 1. UNDER 15,000 SQ. FEET.
- ❑ 2. 15,000 TO 44,999 SQ. FEET
- ❑ 3. 50,000 TO 99,999 SQ. FEET
- ❑ 4. 100,000 TO 249,999 SQ. FEET
- ❑ 5. 250,000 TO 499,000 SQ. FEET
- ❑ 6. 500,000 TO 1 MILL. SQ. FEET.
- ❑ 7. 1 MILL. SQ. FEET OR MORE

13. How many buildings are included in that estimate:

SPECIFY NUMBER : _____

Section D: General

14. How many stories high is the main building at your facility?

_____ # OF STORIES

15. Rank the following types of fuel used in your primary production processes from the most consumed to least consumed? (1 = MOST CONSUMED, 4=LEAST CONSUMED)

RANK

____ 1. GAS

____ 2. ELECTRICITY

____ 3. OIL

____ 4. OTHER (PLEASE SPECIFY) _____

16. Do you have any dual fuel equipment in your facilities?

❑ 1. YES (Specify equipment _____)

❑ 2. NO

17. Does your facility's electricity usage fluctuate by more than 5% due to changes in temperature during the summer?

❑ 1. YES

Which of the following end-uses are responsible for these fluctuations:

❑ 1.1 AIR-CONDITIONING

❑ 1.2 PROCESS COOLING

❑ 1.3 OTHERS _____

❑ 2. NO

18. Are building-wide HVAC or energy management and process control technologies used in your facilities?

❑ 1. YES

❑ 2. NO

19. Which of the following electricity data do you have access to in real-time (with a lag time of 30 minutes or less)? (PLEASE CHECK ALL THAT APPLY)

- ❑ 1. INTERVAL ELECTRICITY USAGE
- ❑ 2. CUSTOMER BASELINE LOAD (CBL)
- ❑ 3. CURTAILMENT EVENT PERFORMANCE
- ❑ 4. WHOLESALE ELECTRICITY MARKET PRICES

20. Please rank the following list of real-time information access opportunities in the order of importance that may help your firm to become more demand responsive: (1=MOST IMPORTANT, 5=LEAST IMPORTANT)

RANK

_____ 1. ACCESS TO INTERVAL ELECTRICITY USAGE DATA

_____ 2. ACCESS TO CUSTOMER BASELINE LOAD (CBL)

_____ 3. ACCESS TO CURTAILMENT EVENT PERFORMANCE

_____ 4. WHOLESALE ELECTRICITY MARKET PRICES

_____ 5. USER DEFINABLE EMAIL/PAGER NOTIFICATION SYSTEM

21. For the month of July 2002, approximately what was your: (Estimate if necessary)

1. Billing kWh _____

2. Billing kW _____

22. What was your maximum demand: (Estimate if necessary)

1. So far this summer: _____kW

2. This past winter: _____ kW

23. On average during the summer months, what percent of your organization's total monthly operating cost is due to electricity cost?

- ❑ 1. LESS THAN 1%
- ❑ 2. BETWEEN 1% AND 3%
- ❑ 3. BETWEEN 4% AND 5%
- ❑ 4. BETWEEN 6% AND 10%
- ❑ 4. GREATER THAN 10%

24. Please rank the following periods according to your facility's usage of electricity from highest to lowest use (1=HIGHEST USE PERIOD, 4=LEAST USE PERIOD):

RANK

_____ 1. 8:00 A.M. – 11:59 A.M.

_____ 2. 12 NOON – 4:59 P.M.

_____ 3. 5:00 P.M. – 9:59 P.M.

_____ 4. 10:00 P.M. – 7:59 A.M.

25. Of the following list of actions, which would you plan to take if you were asked to curtail electricity consumption? (CHECK ALL THAT APPLY)

- ❑ 1. NONE
- ❑ 2. START "ON-SITE" GENERATION (PLEASE SPECIFY CAPACITY BY FUEL TYPE)
  - ❑ 2.1 Diesel fuel _____kW
  - ❑ 2.2 Natural gas _____kW

- ❑ 2.3 Biogas _____kW
- ❑ 2.4 Dual fuel _____kW

❑ 3. COMMUNICATE TO EMPLOYEE/OCCUPANTS TO CONSERVE

Industrial process/manufacturing related measures

❑ 4. SHUT DOWN PLANT

❑ 5. COMPLETELY HALT MAJOR PRODUCTION PROCESSES

❑ 6. ALTER MAJOR PRODUCTION PROCESSES

Buildings related measures

❑ 7. TURN OFF OR DIM LIGHTS

❑ 8. INCREASE INDOOR TEMPERATURE (E.G., RESET THERMOSTAT, TURN OFF COOLING EQUIPMENT)

❑ 9. REDUCE PLUG (OFFICE EQUIPMENT) LOADS

❑ 10. TURN OFF OR LIMIT USE OF ELEVATORS, ESCALATORS

❑ 11. OTHERS (PLEASE EXPLAIN)

_____

PRL Audit question

26. If you have curtailed electricity consumption within the past two years, please rank the effectiveness of load curtailment measures implemented? (Use a scale from 1 through 5, with 5 being very effective and 1 not effective)

Measure	Rank
General measures:	
1. START "ON-SITE" GENERATION……..	_____
2. ASK EMPLOYEE/OCCUPANTS TO CONSERVE ……..	_____

Industrial process/manufacturing related measures:

3. SHUT DOWN PLANT…..……_____

4. COMPLETELY HALT MAJOR PRODUCTION PROCESSES._____

5. ALTER MAJOR PRODUCTION PROCESSES……....._____

Buildings related measures:

6. TURN OF OR DIM LIGHTS……..._____

7. INCREASE INDOOR TEMPERATURE (E.G. RESET THERMOSTAT,TURN OFF COOLING EQUIPMENT …….._____

8. REDUCE PLUG (OFFICE EQUIPMENT) LOADS……..._____

9. TURN OFF ELEVATORS, ESCALATORS……..._____

10. OTHERS (PLEASE SPECIFY) _____ ……..._____

PRL Audit question

27. Did you meet your load reduction target?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

28. How would you plan to implement these load curtailment actions?

- ❑ 1. MANUALLY (E.G. OPERATOR/OCCUPANTS TURN OFF LIGHTS, RESET THERMOSTATS, ETC.)

  Are your load curtailment actions documented in a procedures or operations manual?

- ❑ 1.1 YES
- ❑ 1.2 NO

❑ 2. SEMI-AUTOMATED (E.G. OPERATOR IMPLEMENTS CHANGES THAT ARE PROGRAMMED INTO A BUILDING MANAGEMENT SYSTEM)

❑ 3. FULLY-AUTOMATED (E.G. ACTIONS/ACTIVITIES ARE IMPLEMENTED VIA DIRECT CONTROL FROM AN OUTSIDE ENTITY or ACTIONS THAT ARE PRE-PROGRAMMED INTO EMCS AND INVOKED WITHOUT FACILITY OPERATOR INTERVENTION)

29. What is the largest impediment to shifting electricity usage at your facility from the hours of 12 Noon through 6 P.M. to other hours of the day?

❑ 1. COMFORT OF BUILDING OCCUPANTS

❑ 2. LABOR CONTRACTS

❑ 3. PRODUCTION SCHEDULES

❑ 4. EMPLOYEE SAFETY

❑ 5. ELECTRICITY PROVIDER RATE DESIGN

❑ 6. OTHER (PLEASE SPECIFY) _____

30. To what extent would you say that your organization evaluates energy efficient options when undertaking major capital improvement projects? (1=NOT AT ALL EVALUATED, 5=EXTENSIVELY EVALUATED)

NOT AT ALL 1 2 3 4 5 EXTENSIVELY

31. Which of the following items of equipment has your organization purchased or upgraded within the past 5 years with the key purpose to reduce electricity costs? (Interviewer checks all that apply)

- ❑ 1. NONE
- ❑ 2. DISTRIBUTED ENERGY RESOURCES (e.g., Micro-turbines)
- ❑ 3. MORE EFFICIENT ELECTRIC MOTORS
- ❑ 4. MORE EFFICIENT REFRIGERATION UNITS
- ❑ 5. HIGH EFFICIENCY LIGHTING AND/OR OCCUPANCY SENSORS
- ❑ 6. HIGH EFFICIENCY PUMPS (PROCESS or HVAC)
- ❑ 7. HIGH EFFICIENCY CHILLER OR PACKAGED HVAC UNITS
- ❑ 8. VARIABLE SPEED DRIVES OR VFDs
- ❑ 9. ENERGY MANAGEMENT AND CONTROL SYSTEMS
- ❑ 10. ELECTRICAL METERS FOR SUBMETERING
- ❑ 11. OTHER (PLEASE SPECIFY) _____

32. Which of the following items of equipment has your firm installed or upgraded in 2001 or 2002 specifically to assist in electricity load management? (CHECK ALL THAT APPLY)

- ❑ 1. NONE **GO TO Q. 35**
- ❑ 2. NEW INTERVAL METERS AT SERVICE ENTRANCE
- ❑ 3. NEW INTERVAL SUB-METERS AT MAJOR LOADS
- ❑ 4. ENERGY INFORMATION AND MANAGEMENT SYSTEMS TO MONITOR USAGE REDUCTIONS (e.g. EPO)
- ❑ 5. AUTOMATION ENHANCEMENTS FOR IMPROVED LOAD MANAGEMENT

- ❑ 6. AUTOMATION/CONNECTIVITY ENHANCEMENTS FOR LOAD AGGREGATION
- ❑ 7. NOTIFICATION TECNOLOGY (e.g. PAGERS)
- ❑ 8. DIRECT LOAD CONTROL DEVICES FOR LIGHTING SYSTEM
- ❑ 9. DIRECT LOAD CONTROL DEVICES FOR CYCLING OFF EQUIPMENT
- ❑ 10. INSTALL "ON-SITE" GENERATORS
- ❑ 11. TECHNOLOGY IMPROVEMENTS/UPGRADES THAT ALLOW EXISTING ON-SITE GENERATORS TO PARTICIPATE IN PRL PROGRAMS (e.g., parallel switchgear, controls)
- ❑ 12. OTHER (PLEASE SPECIFY)_____

33. Which of the following outside entities assisted your firm in purchasing this equipment? (CHECK ALL THAT APPLY)

- ❑ 1. NO OUTSIDE ASSISTANCE WAS RECEIVED **GO TO Q. 35**
- ❑ 2. NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA)
- ❑ 3. ELECTRICITY PROVIDER
- ❑ 4. CURTAILMENT SERVICE PROVIDER
- ❑ 5. OTHER (PLEASE SPECIFY) _____

34. How important was this financial assistance to your decision to participate in either the Emergency Demand Response Program (EDRP), the Day-Ahead Demand Response Program (DADRP), or the Installed Capacity Special Case Resource (SCR) program in 2002? (1=NOT IMPORTANT, 5=VERY IMPORTANT)

NOT IMPORTANT 1 2 3 4 5 VERY IMPORTANT

Part 2: Value of information

Section A: General

35. During the late winter and spring of 2002, did you attend any informational presentations where demand reduction programs that provide payment for a reduction in electricity use during specified times were discussed?

- ❑ 1.YES
- ❑ 2.NO **GO TO Q. 38**

36. Who sponsored these informational presentations (CHECK ALL THAT APPLY)?

- ❑ 1. NEW YORK STATE ENERGY RESEARCH AND DEVELOPMENT AUTHORITY (NYSERDA)
- ❑ 2. NEW YORK STATE DEPARTMENT OF PUBLIC SERVICE
- ❑ 3. ELECTRICITY PROVIDER: (PLEASE SPECIFY) _____
- ❑ 4. OTHER (PLEASE SPECIFY) _____

37. In general, how useful was the information you received at these informational presentations in helping you to understand these demand reduction programs?

- ❑ 1. VERY USEFUL
- ❑ 2. SOMEWHAT USEFUL
- ❑ 3. SLIGHTLY USEFUL
- ❑ 4. NOT AT ALL USEFUL

38. Did you receive NYSERDA's 2002 brochure describing the NYISO's Demand Reduction programs?

- ❑ 1. YES
  - 1.1. HOW WELL WAS THE INFORMATION PRESENTED? (1=TOO SIMPLISTIC, 5=TOO COMPLICATED)

    TOO SIMPLISITIC 1 2 3 4 5 TOO COMPLICATED
  - 1.2. HOW USEFUL WAS IT? (1=NOT AT ALL USEFUL, 5=VERY USEFUL)

    NOT AT ALL USEFUL 1 2 3 4 5 VERY USEFUL
- ❑ 2. NO
- ❑ 3. DON'T KNOW

39. Did you receive NYSERDA's 2002 Smart Metering brochure?

- ❑ 1. YES
  - 1.1. HOW WELL WAS THE INFORMATIVE PRESENTED? (1=TOO SIMPLISTIC, 5=TOO COMPLICATED)

    TOO SIMPLISITIC 1 2 3 4 5 TOO COMPLICATED
  - 1.2. HOW USEFUL WAS IT? (1=NOT AT ALL USEFUL, 5=VERY USEFUL)

    NOT AT ALL USEFUL 1 2 3 4 5 VERY USEFUL
- ❑ 2. NO
- ❑ 3. DON'T KNOW

40. Did you receive NYSERDA's 2002 Low-cost /No-cost Demand Reduction Strategies brochure? (CHECK ALL THAT APPLY)?

- ❑ 1. YES

  1.1. HOW WELL WAS THE INFORMATION PRESENTED? (1=TOO SIMPLISTIC, 5=TOO COMPLICATED)

  TOO SIMPLISITIC 1 2 3 4 5 TOO COMPLICATED

  1.2. HOW USEFUL WAS IT? (1=NOT AT ALL USEFUL, 5=VERY USEFUL)

  NOT AT ALL USEFUL 1 2 3 4 5 VERY USEFUL

- ❑ 2. NO
- ❑ 3. DON'T KNOW

41. Did your firm ever participate in any of the following electric utility sponsored load management programs prior to ***2001*** (CHECK ALL THAT APPLY):

- ❑ 1. REAL-TIME PRICING PROGRAM
- ❑ 2. INTERRUPTIBLE OR CURTAILABLE LOAD PROGRAM
- ❑ 3. TIME OF USE RATE PROGRAM
- ❑ 4. OTHER (PLEASE SPECIFY)

_____

Part 3: Factors influencing decision to participate

<u>Section A: General</u>

42. In the future, if you were only allowed to participate in either the ICAP Special Case Resource program or the Emergency Demand Response Program (EDRP), ***but not both***, what would you do?

- ❑ 1. PARTICIPATE IN EDRP ONLY

- ❑ 2. PARTICIPATE IN ICAP SCR ONLY
- ❑ 3. PARTICIPATE IN NEITHER PROGRAM
- ❑ 4. DON'T KNOW/NOT APPLICABLE

Section B: EDRP Participant

If more EDRP resources are available than are needed during a curtailment event, the NYISO may adopt a protocol to determine which participants to call for each event.

43. Which of the following protocols would you prefer the NYISO use:

- ❑ 1. EVERY EDRP PARTICIPANT IS ASKED TO CURTAIL THE SAME PORTION OF THEIR SUBSCRIBED LOAD AND IS ONLY PAID ON THAT AMOUNT
- ❑ 2. EDRP PARTICIPANTS SUBMIT A MINIMUM NOTICE PERIOD UPON REGISTRATION AND LOAD REDUCTIONS OF THE AMOUNT NEEDED ARE CALLED IN RANK ORDER BEGINNING WITH THOSE INDICATING THE SHORTEST MINIMUM NOTICE PERIOD.
- ❑ 3. EDRP PARTICIPANTS SUBMIT A MINIMUM PRICE GUARANTEE FOR CURTAILMENT UPON REGISTRATION AND LOAD REDUCTIONS OF THE AMOUNT NEEDED ARE CALLED IN RANK ORDER BEGINNING WITH THOSE INDICATING THE LOWEST MINIMUM PRICE GUARANTEE

44. If the protocol you just chose were adopted by the NYISO, would you continue to participate in the EDRP?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

Part 4: Factors influencing decision to not participate

Section A: ICAP SCR Non-Participant

45. Are you aware of the NYISO's ICAP Special Case Resource (SCR) program?

- ❑ 1. YES
- ❑ 2. NO **GO TO PART 4 SECTION B**

46. Which one of the following best describes your firm's main reason for not participating in the ICAP SCR program this year?

- ❑ 1. POTENTIAL BENEFITS DON'T JUSTIFY THE RISKS
- ❑ 2. PENALTY IS TOO SEVERE
- ❑ 3. PAYMENTS ARE TOO LOW
- ❑ 4. UNABLE TO SHIFT USAGE
- ❑ 5. PROGRAM CONFLICTS WITH MY RETAIL ELECTRICITY CONTRACT OR RATE
- ❑ 6. INADEQUATE KNOWLEDGE OF ICAP SCR PROGRAM REQUIREMENTS

47. Would you participate in the ICAP SCR program if load curtailment events were limited to a total of 20 hours for the months of May – October?

- ❑ 1. YES
- ❑ 2. NO

- ❑ 3. DON'T KNOW

48. Would you participate in the ICAP SCR program if load curtailment events were not called on more than 3 consecutive days?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

49. Would you participate in the ICAP SCR program if you also received an energy payment for your load curtailment equal to the prevailing Real-time energy price?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

Section B: EDRP Non-Participant

50. Are you aware of the NYISO's Emergency Demand Response Program (EDRP)?

- ❑ 1. YES
- ❑ 2. NO **GO TO PART 4 SECTION C**

51. Which one of the following best describes your firm's main reason for not participating in the Emergency Demand Response Program this year?

- ❑ 1. POTENTIAL BENEFITS DON'T JUSTIFY THE RISKS
- ❑ 2. PAYMENTS ARE TOO LOW
- ❑ 3. UNABLE TO SHIFT USAGE
- ❑ 4. PROGRAM CONFLICTS WITH MY RETAIL ELECTRICITY CONTRACT OR RATE
- ❑ 5. INADEQUATE KNOWLEDGE OF EDRP REQUIREMENTS
- ❑ 6. ENVIRONMENTAL PERMITTING FOR GENERATION

Section C: DADRP Non-Participant

52. Are you aware of the NYISO's Day-Ahead Demand Response Program (DADRP)?

- ❑ 1. YES
- ❑ 2. NO **GO TO PART 5**

53. Which of one of the following best describes the primary reason for not participating in the Day-Ahead Demand Response program this year?

- ❑ 1. POTENTIAL BENEFITS DON'T JUSTIFY THE RISKS
- ❑ 2. PENALTY IS TOO SEVERE (PROGRAM DESIGN RELATED)
- ❑ 3. PAYMENTS ARE TOO LOW (PROGRAM DESIGN RELATED)
- ❑ 4. UNABLE TO SHIFT USAGE (TECHNOLOGICAL BARRIERS)
- ❑ 5. PROGRAM CONFLICTS WITH MY RETAIL ELECTRICITY CONTRACT OR RATE (ORGANIZATIONAL BARRIERS)
- ❑ 6. INADEQUATE KNOWLEDGE OF DADRP REQUIREMENTS

PRL Audit question

DRILL DOWN INTO EACH CATEGORY FOR SPECIFIC REASON

PRL Audit question

54. Which of the following list of factors contributed directly to your decision not to sign up for the 2002 Day-Ahead Demand Response Program (DADRP)? (INTERVIEWER CHECKS ALL THAT APPLY AND PROBES FOR MOST IMPORTANT)

Program design related:

- ❑ 1. UNCERTAINTY ABOUT CBL (CBL calculation method, or actual CBL)
- ❑ 2. UNCERTAIN PAYMENT LEVEL FOR REDUCTION
- ❑ 3. TIMING OF THE PAYMENT
- ❑ 4. UNCERTAINTY ABOUT WHEN BIDS WILL BE ACCEPTED
- ❑ 5. PENALTY FOR NON-COMPLIANCE or NON-PERFORMANCE
- ❑ 6. REQUIRED MINIMUM 100 KW LOAD REDUCTION
- ❑ 7. UNABLE TO MEET PROGRAM PROVIDER'S BIDDING REQUIREMENTS
- ❑ 8. DIESEL BUGS NOT ALLOWED

Organizational barriers at facility:

- ❑ 9. A LANDLORD/TENANT LEASE PARTICIPATION LIMITATION E.G., SUB-METERING
- ❑ 10. NOT ENOUGH STAFF AVAILABLE TO ADMINISTER PROGRAM
- ❑ 11. BECAME AWARE OF THE PROGRAM TOO LATE
- ❑ 12. DIFFICULTY IN COMMUNICATING PROGRAM DETAILS TO MANAGERS
- ❑ 13. INTERNAL ACCOUNTING PRACTICES MADE IT TOO DIFFICULT TO OBTAIN FUNDS FOR ENABLING TECHNOLOGIES

Technology related barriers

- ❑ 14. COST OF METERING AND COMMUNICATIONS EQUIPMENT IS TOO HIGH, GIVEN EXPECTED REVENUE
- ❑ 15. LATE INSTALLATION OF METERING AND/OR COMMUNICATIONS EQUIPMENT
- ❑ 16. INABILITY TO CONTROL/MONITOR LOAD REDUCTIONS IN NEAR REAL-TIME
- ❑ 17. IT SYSTEM CONCERNS (E.G. FIREWALLS, SECURITY)
- ❑ 18. COST FOR ADMINISTERING PROGRAM TOO HIGH FOR EXPECTED REVENUE OR PERCEIVED RISKS
- ❑ 19. OTHER (PLEASE SPECIFY) _____

55. Would you participate in the Day-Ahead Demand Response Program (DADRP) if your Customer Baseline Load (CBL) were made available to you prior to the time your bid is due?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

56. The Day-Ahead Demand Response Program (DADRP) currently requires a participant to submit bids on a daily basis. Which of the following methods for submitting bids would you prefer?

- ❑ 1. DAILY
- ❑ 2. WEEKLY
- ❑ 3. MONTHLY

57. If the NYISO adopted the bidding methodology you just chose, would you participate in the Day-Ahead Demand Response Program (DADRP)?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

58. Would you participate in the Day-Ahead Demand Response Program (DADRP) if instead of being assessed a penalty for non-compliance, you were required to purchase the deficient curtailment amount at the Real-Time market price?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

59. Would you participate in the Day-Ahead Demand Response Program (DADRP) if the Emergency Demand Response Program (EDRP) were eliminated?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW

Part 5: Barriers to Customer Participation

<u>Section A: General</u>

PRL Audit question

60. Please rank the relative importance (using a scale of 1 to 5, with 5 being "decisive", 3 being "Important" and 1 being" not a factor") of the following factors in your firm's decision to participate in a demand reduction program:

	Scale
Savings $ on my utility bill	_____
Community/public interest in avoiding blackouts	_____
Voluntary nature of performance in the EDRP program	_____
Obtaining energy information management software and/or interval meters	_____
Financial incentives offered by NYISO or LSE/CSP	_____
Other (please specify)_____	

PRL Audit question

61. How detailed of an assessment did you undertake to evaluate the technical feasibility of participation in the DADRP Program? (Rate on a scale of 1 to 5)

No Detail 1 2 3 4 5 Very Detailed

(INTERVIEWER PROBES TO FIND OUT SPECIFICS)

PRL Audit question

62. How detailed of an assessment did you undertake to evaluate the financial feasibility of participation in the DADRP Program? (Rate on a scale of 1 to 5)

No Detail 1 2 3 4 5 Very Detailed

(INTERVIEWER PROBES TO FIND OUT SPECIFICS)

PRL Audit question

63. How comfortable are you with the following activities that may be necessary to participate in the DADRP program (rate from 1 to 5; 1 is not comfortable and 5 is very comfortable):

Measures	Rate
1. Creating a load curtailment plan to meet a specific kW reduction target	
2. Monitoring day-ahead energy prices to determine whether and if to bid	
3. Determining at what price to bid	

[Interviewer probes activity areas in more detail in Q. 63 – 67 for areas with low ratings]

PRL Audit question

64. Are you confident that if you committed to a load curtailment target you could actually meet that target? PROBE

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW
- ❑ 4. NOT APPLICABLE

PRL Audit question

65. Would you consider assistance from a utility representative or an aggregator to more accurately quantify your load management capabilities?

- ❑ 1. YES

- ❑ 2. NO
- ❑ 3. DON'T KNOW
- ❑ 4. NOT APPLICABLE

PRL Audit question

66. Do you have staff who could monitor the day ahead electricity prices in order to determine when and if to bid? Do you feel that you need to monitor DAM prices in order to participate? [PROBE See Answer to Part 4, Section C, Q 54-1]

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW
- ❑ 4. NOT APPLICABLE

PRL Audit question

67. Does the prospect of having to decide when and at what level to submit bids simply represent too cumbersome of a task to make participation worthwhile? [PROBE See Answer to Part 4, Section C, Q 54-3]

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW
- ❑ 4. NOT APPLICABLE

PRL Audit question

68. Would you have sufficient staff to implement a load curtailment strategy capable of reducing load by 5-10% or 100 kW? [PROBE See Answer to Part 4, Section C, Q 54-3]

- ❑ 1. YES

- ❑ 2. NO

(INTERVIEWER PROBES WHY – E.G., DISPERSED FACILITIES?)

PRL Audit question

69. Do you currently have sufficient capability in your process/building automation systems to perform load reductions automatically or semi-automatically? [PROBE See Answer to Part 1, Q 9: See Answer to Part 4, Section C, Q54-4]

- ❑ 1. YES **GO TO Q.71**
- ❑ 2. NO

PRL Audit question

70. Please estimate approximate minimum cost to upgrade and automate buildings or process control infrastructure to implement a semi- or fully-automated load reduction strategy?

- ❑ 1. LESS THAN $10,000
- ❑ 2. $10,001 TO $50,000
- ❑ 3. $50,000 TO $100,000
- ❑ 4. $100,000 TO $500,000
- ❑ 5. GREATER THAN $500,000

(INTERVIEWER PROBES WHY – E.G., DISPERSED FACILITIES?)

PRL Audit question

71. At present, do you have access to interval electricity consumption data for your entire facility

- ❑ 1. IN NEAR REAL-TIME **GO TO Q.74**

- ❑ 2. ON A DAY-AFTER BASIS,
- ❑ 3. ON A LATER THAN DAY-AFTER BASIS
- ❑ 4. NOT AT ALL

PRL Audit question

72. Since you do not have near real-time load monitoring, would you have sufficient staff to perform any necessary monitoring tasks during load curtailment periods? [PROBE See Answer to Part 4, Section C, Q 54-3, 54-4]

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW
- ❑ 4. NOT APPLICABLE

PRL Audit question

73. What is the price threshold at which you would bid?

1. PLEASE SPECIFY THE PRICE PER KWH:	IN $/KWH
2. HOW MUCH LOAD (KW) COULD YOU CURTAIL:	IN KW
3. OVER WHAT DURATION (HOURS):	IN HOURS

PRL Audit question

74. If your load reduction response were fully automated, would it change your threshold price, or amount and time period that you could curtail?

- ❑ 1. YES

1.1 PLEASE SPECIFY THE PRICE PER KWH:	IN $/KWH
1.2 HOW MUCH LOAD (KW) COULD YOU CURTAIL:	IN KW
1.3 OVER WHAT DURATION (HOURS):	IN HOURS

- ❑ 2. NO

Part B: Commercial/Institutional Customers

PRL Audit question

75. How often would you be willing to bid these load reduction actions without impacting occupants, tenants, or staff in an unacceptable way at your specified bid price threshold? [SEE ANSWER TO PART 1, Q,29-1, 29-4]

- ❑ 1. 1- 5 TIMES PER YEA R
- ❑ 2. 6-10 TIMES PER YEAR
- ❑ 3. 11 – 20 TIMES PER YEAR
- ❑ 4. MORE THAN 20 TIMES PER YEAR

Probe: frequency to affect comfort or productivity of occupants

_____

PRL Audit question

76. How many consecutive days are you willing to bid load reductions at your specified bid price threshold?

- ❑ 1. 2 DAYS
- ❑ 2. 3 DAYS
- ❑ 3. 4 –5 DAYS
- ❑ 4. MORE THAN 5 DAYS

PRL Audit question

77. On a scale of 1-5 (e.g. 5 is very concerned), how concerned are you about the comfort of occupants, tenants, or staff in your buildings? [SEE ANSWER TO PART 1, Q. 29-1]

_____ Score

PRL Audit question

78. Would you consider raising the indoor temperature levels by 3-4 degrees for ~4 hours during the summer at your facility if you received financial incentive payments from a Demand Response program for the value of the load reduction?

- ❑ 1. YES
- ❑ 2. NO
- ❑ 3. DON'T KNOW
- ❑ 4. NOT APPLICABLE

Probe how many degrees increase in temperature would be acceptable?

Part C: Industrial Customers only

PRL Audit question

79. How often would you be willing to bid these load reduction actions (e.g., shut down any large processes during peak period and/or shift production altogether from peak to off-peak) at your specified bid price threshold? [SEE ANSWER TO PART 1, Q.29-2, 29-3]

- ❑ 1. 1- 5 TIMES PER YEAR
- ❑ 2. 6-10 TIMES PER YEAR
- ❑ 3. 11 – 20 TIMES PER YEAR
- ❑ 4. MORE THAN 20 TIMES PER YEAR

Probe: frequency to affect comfort or productivity of occupants

PRL Audit question

80. How many consecutive days are you willing to bid load reductions at your specified bid price threshold?

- ❑ 1. 2 DAYS
- ❑ 2. 3 DAYS
- ❑ 3. 4 –5 DAYS
- ❑ 4. MORE THAN 5 DAYS

PRL Audit question

81. On a scale of 1-5 (e.g. 5 is very concerned), how concerned are you about the comfort of occupants, tenants, or staff in your buildings? [SEE ANSWER TO PART 1, Q. 29-1]

_____ Score

Part D: General

PRL Audit question

82. Here is a list of technologies that enable load curtailments/reductions. What technologies did you consider for participation in EDRP or DADRP and then ultimately decide not to invest in?

- ❑ 1. INTERVAL METERS AT SERVICE ENTRANCE
- ❑ 2. INTERVAL SUB-METERS AT MAJOR LOADS
- ❑ 3. ENERGY INFORMATION SYSTEMS TO MONITOR COMPLIANCE
- ❑ 4. AUTOMATION ENHANCEMENTS FOR IMPROVED LOAD MANAGEMENT
- ❑ 5. AUTOMATION/CONNECTIVITY ENHANCEMENTS FOR LOAD AGGREGATION

- ❑ 6 NOTIFICATION TECNOLOGY (e.g. PAGERS)
- ❑ 7. DIRECT LOAD CONTROL DEVICES FOR LIGHTING SYSTEM
- ❑ 8. DIRECT LOAD CONTROL DEVICES FOR CYCLING OFF EQUIPMENT
- ❑ 9.INSTALL "ON-SITE" GENERATORS
- ❑ 10. TECHNOLOGY IMPROVEMENTS/UPGRADES THAT ALLOW EXISTING ON-SITE GENERATORS TO PARTICIPATE IN PRL PROGRAMS (e.g., parallel switchgear, controls)
- ❑ 11. OTHER (PLEASE SPECIFY)_____

Probe following issues:

- Results of technical feasibility studies,
- Availability of capital,
- Required economic payback time ,
- Interest in alternative financing and cost-sharing.

_____

PRL Audit question

83. What were the major factors in your decision not to invest in these technologies (listed above)? List Factors

_____

PRL Audit question

84. Here are ranges of cost for load reduction technologies

Technology		Capital Cost incl. Installation
HVAC	Elec. chiller replacement (750 ton, COP=5.4)	$300-$400/ton
	Nat. Gas absorption chiller (2-stage, 300 ton, COP=1.0)	$900 – $1100/ton
	Package HVAC unit (30 ton, EER = 10)	$650 – $800/ton
Motors	High efficiency motors (40 HP)	1300 – 1600/unit
	High efficiency motors (100 HP)	19,000-20,000/unit
	VFD (20-100 HP)	$100-$130/HP
Switchgear for backup generators	Switchgear for parallel operation of backup gensets (incl. Controls)	$100 – $150/kW
Automation	Controls/communication and automation technology	$300-$1000/node of the control network

Given the technology cost ranges above, what is an acceptable payback period for your firm to invest in equipment or controls to facilitate automated load curtailments?

Specify: _____ in years

PRL Audit question

85. What would need to be your break-even point requirements, in terms of $/kW, for investment in load curtailment automation and monitoring technology?

_____

PRL Audit question

86. Some of the technologies used to assist customers in implementing load curtailments potentially have other benefits. How valuable would these additional benefits associated with the following technologies be to you (rate from 1 to 5; 1 is low and 5 is high):

Technology	Benefit	Rate
1. Interval meters with two-way communications	Better manage peak energy and demand charges with access to day-after access to facility interval data	
2. Load Control	Shed load and/or initiate onsite generation, in order to reduce demand charges	
3. Upgrade switchgear for onsite generation	Increase load management flexibility to modify load profile for more desirable energy procurement	
4. Upgrade onsite generation with dual-fuel capability	Fuel flexibility to mitigate fuel price volatility	
5. Enhanced energy management or control system	Ability to schedule and/or automate load management, and reduce labor for facility operations, increase reliability to integration with maintenance procedures	
6. Energy information tools	Ability to view interval electricity data and aggregate data over multiple buildings, increase understanding of loads and enhance ability to modify load profile for lower cost energy procurement	

(PROBE: Are customers more likely to incur the investment in automation if they also believe that they can reduce energy usage through energy efficiency/management?)

PRL Audit question

87. How confident are you that the DADRP program will continue in the future on a scale of 1-5 (1 is not confident; 5 is very confident)?

Specify: _____

PRL Audit question

88. How confident are you that the EDRP and ICAP programs will continue in the future on a scale of 1-5 (1 is not confident; 5 is very confident)?

Specify: _____

PROBE – for those customers who perceive significant regulatory risk (1 or 2), does it affect their willingness to invest or investment decisions?

Part 6: New programs to be offered

The NYISO is considering several new Demand Reduction programs for the future. Your answers to the following questions will help the NYISO in developing these new programs to ensure they will be attractive to end-use customers.

Section A: General

89. What is the least amount of notice time you would require to reduce ***a portion*** of your electricity usage during the hours of 12 Noon to 6 P.M. in the summertime?

- ❑ 1. 15 MINUTES
- ❑ 2. 30 MINUTES
- ❑ 3. 1 HOUR
- ❑ 4. 2 HOURS
- ❑ 5. 4 HOURS

❑ 6. OTHER (PLEASE SPECIFY)

_____

90. What is the likelihood that you would participate in a demand reduction program that paid you the prevailing Real-Time market price for voluntarily curtailing load at any time you choose.

❑ 1. DEFINITELY WOULD PARTICIPATE

❑ 2. PROBABLY WOULD PARTICIPATE

❑ 3. PROBABLY WOULD NOT PARTICIPATE

❑ 4. DEFINITELY WOULD NOT PARTICIPATE

91. What is the likelihood that you would participate in a demand reduction program that had the following two features:

a) Paid you the prevailing Real-Time electricity market price for reducing a specific amount of your electricity usage when your indicated price threshold is exceeded; **and**

b) Penalized you at the Real-Time price for the difference between your indicated and actual load curtailment.

❑ 1. DEFINITELY WOULD PARTICIPATE

❑ 2. PROBABLY WOULD PARTICIPATE

❑ 3. PROBABLY WOULD NOT PARTICIPATE

❑ 4. DEFINITELY WOULD NOT PARTICIPATE

92. What is the likelihood that you would participate in a demand reduction program that had the following three features:

    a) Provided you an up-front payment to agree to reduce a specific amount of electricity usage when called upon to do so during the hours of Noon to 6 p.m. with only 30 minutes notice; **and**
    b) Paid you the prevailing Real-Time electricity market price for your load curtailment when called upon to reduce load; **and**
    c) Penalized you at the Real-Time price for the difference between your indicated and actual load curtailment.

    - ❑ 1. DEFINITELY WOULD PARTICIPATE
    - ❑ 2. PROBABLY WOULD PARTICIPATE
    - ❑ 3. PROBABLY WOULD NOT PARTICIPATE
    - ❑ 4. DEFINITELY WOULD NOT PARTICIPATE

93. If you are dissatisfied with any of the NYISO's Demand Reduction programs: EDRP, DADRP, or ICAP SCR, please explain which program it is and what could be changed to make that program better?

    _____

    _____

    _____

Appendix 3B

Survey Part 2: Conjoint Survey

This appendix contains the conjoint survey used in the 2002 Customer Acceptance Survey. Sections represent groups of questions that were asked of respondents, based on participation criteria. This survey was faxed to respondents who completed Part 1, Customer Acceptance. Respondents returned the completed survey via fax.

2002 Electricity Demand Response Programs

Customer Survey

This summer you participated in one or more of the demand reduction programs offered by NYISO. Load reductions undertaken this summer by program participants are helping to preserve a reliable supply of electricity throughout the state.

NYISO, in cooperation with your electricity provider, has asked Neenan Associates to evaluate the program and recommend improvements for next year. To accomplish these objectives, we need your help by completing a survey. Your opinions regarding how well the current programs meet your needs and expectations are vital to the continuing success of deregulation in New York State. Your responses will be kept confidential and anonymous and will only be reported in combination with those of the many others who will participate in this evaluation.

Drawings and Prizes

There will be two drawings, one from respondents who complete Part I and one from respondents who complete Part II. Complete both parts of the survey and your name will be entered in both drawings.

Survey - Part I

If you complete Part I of the survey, you will be entered in a drawing. The two winners may choose between _____. You must complete all appropriate questions to be eligible for the drawing.

Survey - Part II

If you have completed Part 1 of the survey and we receive the fully completed Survey - Part II by 5:00 p.m. on October 18, 2002, you will also be entered into a drawing where the winner may choose between _____. You must complete all appropriate questions on both parts of the survey to be eligible for this drawing. Since there will only be about 50 people in the drawing, chances of winning this prizes are about 1 in 50.

Drawings will be held at noon on Tuesday, October 22, 2002 at the offices of Neenan Associates. Winners will be notified by telephone on or before Friday, October 25, 2002 using the contact information supplied by each respondent on the questionnaires.

Returning this form:

When you have completed your responses, please fax this document back to the fax number on the survey pages. Within a few days of completing the surveys, you'll receive a postcard confirming that you have been entered in one or both of the drawings.

Thank you for participation in this survey. Good Luck!

Instructions for Part II

THE NEW YORK STATE ELECTRICITY MARKET CURRENTLY OFFERS A SUITE OF DEMAND RESPONSE PROGRAMS THAT ARE AVAILABLE TO END-USE CUSTOMERS. TO ENSURE THAT THESE PROGRAMS MEET CUSTOMERS' NEEDS, THESE PROGRAMS MUST BE EVALUATED AND REFINED REGULARLY. YOUR ANSWERS TO THE QUESTIONS IN THIS SECTION ARE VERY IMPORTANT TO THIS EVALUATION PROCESS.

Each of the following 20 questions displays a set of 4 Demand Response Programs, each containing different configurations of program features. Assume that only these features define the programs. Select the one program from each choice set to which you would most likely subscribe. If you would subscribe to none of the 4 programs within the choice set, select the "None" option. Please indicate your choice by checking the appropriate box. It is very important that you provide an answer for each of the 20 questions.

Please return this survey within 24 hours of completing Part 1 by faxing it to the number displayed at the top of the page. ***Please be sure your Survey ID is included on at least one page so that we can enter you into the second drawing.***

Survey ID:

Explanation of Terms

Payment

- The dollars per kWh you will be paid for reducing electricity usage

Penalty

- The dollars per kWh assessed on the difference between pledged and actual reduction in electricity usage

Start Time

- Time at which you must begin reducing electricity usage

Notice

- Number of hours in advance of the Start Time that you will be notified of your requirement to reduce electricity usage

Duration

- Number of hours after the Start Time that you will be required to maintain the reduction in your electricity usage

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 1

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.25/kWh	$0.75/kWh	$0.50/kWh	$0.10/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.5 x Payment	0.1 x Payment	None	0.25 x Payment	
Start Time	1:00 PM	Noon	11:00 AM	2:00 PM	
Notice	4 Hours	2 Hours	Noon, Day Ahead	30 Minutes	
Duration	2 Hours	1 Hour	30 Minutes	4 Hours	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 2

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.25/kWh	$0.75/kWh	$0.10/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.25 x Payment	0.5 x Payment	None	0.1 x Payment	
Start Time	2:00 PM	11:00 AM	Noon	1:00 PM	
Notice	2 Hours	Noon, Day Ahead	4 Hours	30 Minutes	
Duration	2 Hours	1 Hour	4 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 3

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.75/kWh	$0.10/kWh	$0.25/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.1 x Payment	0.5 x Payment	None	0.25 x Payment	
Start Time	2:00 PM	11:00 AM	1:00 PM	Noon	
Notice	4 Hours	30 Minutes	Noon, Day Ahead	2 Hours	
Duration	1 Hour	2 Hours	4 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 4

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.75/kWh	$0.50/kWh	$0.25/kWh	$0.10/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.25 x Payment	0.5 x Payment	0.1 x Payment	None	
Start Time	1:00 PM	Noon	11:00 AM	2:00 PM	
Notice	Noon, Day Ahead	30 Minutes	2 Hours	4 Hours	
Duration	1 Hour	30 Minutes	4 Hours	2 Hours	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 5

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.75/kWh	$0.50/kWh	$0.25/kWh	$0.10/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.25 x Payment	0.5 x Payment	None	0.1 x Payment	
Start Time	11:00 AM	1:00 PM	2:00 PM	Noon	
Notice	4 Hours	2 Hours	30 Minutes	Noon, Day Ahead	
Duration	30 Minutes	4 Hours	1 Hour	2 Hours	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 6

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.10/kWh	$0.50/kWh	$0.25/kWh	$0.75/kWh	None: I wouldn't subscribe to any of these programs
Penalty	None	0.25 x Payment	0.1 x Payment	0.5 x Payment	
Start Time	11:00 AM	Noon	1:00 PM	2:00 PM	
Notice	2 Hours	30 Minutes	4 Hours	Noon, Day Ahead	
Duration	1 Hour	4 Hours	2 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 7

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.25/kWh	$0.10/kWh	$0.75/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.25 x Payment	0.1 x Payment	0.5 x Payment	None	
Start Time	11:00 AM	2:00 PM	Noon	1:00 PM	
Notice	30 Minutes	Noon, Day Ahead	4 Hours	2 Hours	
Duration	2 Hours	4 Hours	1 Hour	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 8

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.25/kWh	$0.75/kWh	$0.10/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.1 x Payment	None	0.25 x Payment	0.5 x Payment	
Start Time	1:00 PM	Noon	11:00 AM	2:00 PM	
Notice	30 Minutes	Noon, Day Ahead	4 Hours	2 Hours	
Duration	1 Hour	2 Hours	4 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 9

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.75/kWh	$0.50/kWh	$0.10/kWh	$0.25/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.5 x Payment	0.25 x Payment	None	0.1 x Payment	
Start Time	11:00 AM	1:00 PM	2:00 PM	Noon	
Notice	4 Hours	2 Hours	30 Minutes	Noon, Day Ahead	
Duration	1 Hour	4 Hours	30 Minutes	2 Hours	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 10

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.10/kWh	$0.50/kWh	$0.25/kWh	$0.75/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.5 x Payment	None	0.25 x Payment	0.1 x Payment	
Start Time	11:00 AM	Noon	1:00 PM	2:00 PM	
Notice	Noon, Day Ahead	2 Hours	4 Hours	30 Minutes	
Duration	4 Hours	1 Hour	30 Minutes	2 Hours	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 11

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.75/kWh	$0.25/kWh	$0.10/kWh	$0.50/kWh	None: I wouldn't subscribe to any of these programs
Penalty	None	0.5 x Payment	0.25 x Payment	0.1 x Payment	
Start Time	2:00 PM	Noon	1:00 PM	11:00 AM	
Notice	Noon, Day Ahead	30 Minutes	2 Hours	4 Hours	
Duration	1 Hour	4 Hours	2 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 12

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.10/kWh	$0.75/kWh	$0.50/kWh	$0.25/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.5 x Payment	0.1 x Payment	0.25 x Payment	None	
Start Time	1:00 PM	2:00 PM	Noon	11:00 AM	
Notice	4 Hours	2 Hours	Noon, Day Ahead	30 Minutes	
Duration	1 Hour	4 Hours	2 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 13

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.25/kWh	$0.10/kWh	$0.75/kWh	$0.50/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.5 x Payment	0.25 x Payment	0.1 x Payment	None	
Start Time	1:00 PM	2:00 PM	Noon	11:00 AM	
Notice	30 Minutes	2 Hours	Noon, Day Ahead	4 Hours	
Duration	1 Hour	2 Hours	4 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 14

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.10/kWh	$0.25/kWh	$0.75/kWh	None: I wouldn't subscribe to any of these programs
Penalty	None	0.1 x Payment	0.25 x Payment	0.5 x Payment	
Start Time	2:00 PM	Noon	11:00 AM	1:00 PM	
Notice	4 Hours	Noon, Day Ahead	2 Hours	30 Minutes	
Duration	4 Hours	30 Minutes	1 Hour	2 Hours	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 15

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.75/kWh	$0.10/kWh	$0.25/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.1 x Payment	None	0.25 x Payment	0.5 x Payment	
Start Time	1:00 PM	Noon	2:00 PM	11:00 AM	
Notice	Noon, Day Ahead	4 Hours	30 Minutes	2 Hours	
Duration	4 Hours	2 Hours	1 Hour	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 16

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.10/kWh	$0.50/kWh	$0.75/kWh	$0.25/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.1 x Payment	0.25 x Payment	None	0.5 x Payment	
Start Time	Noon	2:00 PM	11:00 AM	1:00 PM	
Notice	30 Minutes	Noon, Day Ahead	2 Hours	4 Hours	
Duration	30 Minutes	2 Hours	1 Hour	4 Hours	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 17

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.25/kWh	$0.10/kWh	$0.75/kWh	$0.50/kWh	None: I wouldn't subscribe to any of these programs
Penalty	None	0.1 x Payment	0.25 x Payment	0.5 x Payment	
Start Time	1:00 PM	11:00 AM	Noon	2:00 PM	
Notice	30 Minutes	2 Hours	Noon, Day Ahead	4 Hours	
Duration	4 Hours	2 Hours	1 Hour	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 18

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.25/kWh	$0.75/kWh	$0.10/kWh	$0.50/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.25 x Payment	0.1 x Payment	0.5 x Payment	None	
Start Time	2:00 PM	11:00 AM	Noon	1:00 PM	
Notice	Noon, Day Ahead	30 Minutes	4 Hours	2 Hours	
Duration	2 Hours	1 Hour	4 Hours	30 Minutes	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 19

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.10/kWh	$0.75/kWh	$0.25/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.5 x Payment	None	0.25 x Payment	0.1 x Payment	
Start Time	11:00 AM	Noon	1:00 PM	2:00 PM	
Notice	Noon, Day Ahead	30 Minutes	2 Hours	4 Hours	
Duration	2 Hours	30 Minutes	4 Hours	1 Hour	
Check one choice	☐	☐	☐	☐	☐

Which of these 4 Demand Response Programs would you choose, if any?

Choice Set 20

	Program 1	Program 2	Program 3	Program 4	None
Payment	$0.50/kWh	$0.10/kWh	$0.25/kWh	$0.75/kWh	None: I wouldn't subscribe to any of these programs
Penalty	0.25 x Payment	None	0.1 x Payment	0.5 x Payment	
Start Time	1:00 PM	2:00 PM	Noon	11:00 AM	
Notice	2 Hours	30 Minutes	Noon, Day Ahead	4 Hours	
Duration	4 Hours	30 Minutes	2 Hours	1 Hour	
Check one choice	☐	☐	☐	☐	☐

2002 NYISO PRL Evaluation

THANK YOU FOR YOUR COOPERATION IN COMPLETING THIS SURVEY!

THE FOLLOWING INFORMATION IS NECESSARY FOR YOU TO BE ENTERED INTO THE DRAWING FOR THIS PART OF THE SURVEY. YOU MUST HAVE COMPLETED ALL RELEVANT QUESTIONS IN THIS QUESTIONNAIRE TO BE ELIGIBLE FOR WINNING.

NAME: _____ (FIRST) _____(LAST)

STREET ADDRESS: _____

CITY: _____ STATE: _____

WORK TELEPHONE: _____ _____ - _____

WORK EMAIL: _____

YOUR NAME WILL BE DETACHED FROM THE QUESTIONNAIRE PRIOR TO DATA ANALYSIS AND WILL NOT BE CONNECTED TO YOUR ANSWERS THEREAFTER.

Chapter 4 - Customer Preferences for Price-Responsive Load Programs

Customer Preferences for PRL Features

Overview

One of the primary objectives of the 2002 evaluation is to better understand customers' decisions regarding participation and performance in the NYISO Demand Response programs. For analysis purposes, customer decisions can be classified into four major areas:

- Current Participation Decisions,
- Continued or Future Participation Decisions,
- Load Reduction Subscription Rates, and
- Actual Event Curtailment Performance.

Current participation decisions include those made both by customers participating in one or more of the three NYISO programs (EDRP, DADRP, and ICAP/SCR) and by informed non-participants, defined as customers that have elected not to enroll in any program but who attended informational meetings regarding the programs. In 2002, customer enrollment increased substantially in the EDRP and ICAP/SCR program, yet it is still critical to gain a better understanding of what motivates the enrollment decision. Because these programs are new and continue to evolve, we must better understand which customers would continue in the programs if critical program features were changed. Moreover, a primary objective of the 2002 evaluation is to characterize the drivers to participation and performance in DADRP, and identify barriers that limit participation and performance in this program.

The amount of load reduction that participants nominate when they subscribe into a PRL program is an important indication of their intention to curtail during an emergency event, or in the case of DADRP, in real-time if their bids are accepted in the day-ahead market (DAM). Each participant's actual performance during emergency events must also be reviewed in order to ascertain how well those intentions were fulfilled. For system dispatchers to view these programs as providing reliable load management resources during times of emergency, it is critical to identify and explain systematic differences between subscription rates and actual performance.

Moreover, because participant acquisition costs are high, CSPs would like to be able to identify factors that lead to higher performance yields.

We hypothesize that decisions about program participation and performance are influenced by the characteristics of customers (e.g., type of business, number of production shifts, electricity usage patterns, etc.), the particular features of PRL programs, the potential influence of financial assistance from NYSERDA or others in purchasing and installing enabling technologies, the usefulness of information received about current programs, past experience with load management programs, and conditions in the market (e.g. expectations about the level of DAM or RTM prices). We explore how these factors interact to influence customer's decisions through two levels of analysis. The first involves a "top-level" analysis using statistical tests to establish association among factors. The second utilizes behavioral choice models to establish the relative importance of key factors in the decision to participate process. In the "top-level" analysis, we focus on exploratory data analysis and hypothesis tests of differences in mean values of key measures of satisfaction, preference, or performance between sub-groups of survey respondents. In particular, we summarize key characteristics of participants in PRL programs and informed non-participants, explore factors that help us to understand and explain customer participation decisions, subscription levels and actual performance, and analyze barriers to participation in the DADRP as well as EDRP and ICAP/SCR programs.

Top-Level Analysis

Methods and Practices

A customer survey was administered through telephone interviews to a sample of 85 program participants and 59 informed non-participants as part of the evaluation of the 2002 NYISO PRL programs. Respondents were asked targeted questions based on their participation decision that included the following topics: information that characterized the customer's primary business activity, facility characteristics and energy usage patterns, load curtailment strategies, factors that influenced their decision whether or not to participate in various PRL programs, barriers to customer participation, and their reaction to potential changes in program design or new program offerings. Details of the survey design and administration are provided in Chapter 3.

In addition, professional engineers from CERTS conducted more extensive and comprehensive telephone interviews (i.e., "PRL audits") with a sub-set of 35 respondents in the

general survey population, in order to further explore factors that customers see as obstacles to participating in the DADRP.[1]

Survey respondents were categorized into four sub-groups for analytical purposes:

- DADRP participants, even if they participated in another program
- Participants in EDRP only
- Participants only in EDRP and ICAP/SCR but not DADRP
- Informed non-participants (INP)

Table 4-1: Survey Sample and Population

Sub-Group	Sample		Population	
	Sample Size, n	Total Subscribed Load (MW)	Population Number, N	Total Subscribed Load (MW)
DADRP	11	131	24	394
EDRP Only	60	69	1522	862
EDRP-ICAP	14	126	165	497
Informed Non-participants	59	N/A	320	N/A
Total	144	326	2031	1752

Informed non-participants were drawn from lists of customers that attended informational workshops on PRL programs sponsored by various New York State agencies during Spring 2002.

The 85 PRL program participants that responded to the survey represent a combined 326 MW of subscribed load reductions, equal to about 19% of that for the entire population of PRL program participants (Table 4-1). Although DADRP respondents are the smallest group in terms of sample size (11), survey respondents represent about one-third of the subscribed load in DADRP. All DADRP respondents had subscribed load reduction levels greater than 5 MW, with a median value of 12 MW (Fig. 4-1). In comparison, the median value for subscribed load reduction for EDRP respondents was much lower (200 kW). The difference in subscribed load

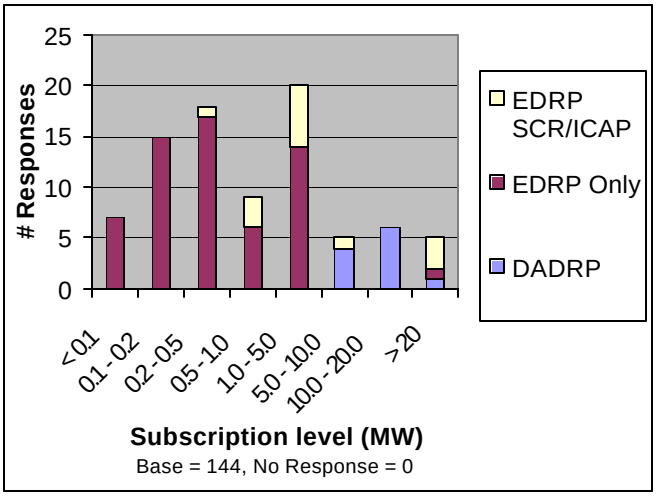


Fig. 4-1: Surve y Respondents' Subscribed Load Reduction

[1] The Consortium of Electric Technology Reliability Solutions (CERTS) team consisted of engineers from Lawrence Berkeley National Laboratory (LBNL) and Pacific Northwest Laboratory (PNL).

reductions partially reflects the program rules for minimum participant size: DADRP was restricted to aggregated bids of at least 1 MW, while the minimum load reduction was 100 kW in EDRP.

Customer Characteristics

Participation and performance in PRL programs may be influenced by the attributes of each customer, e.g., their primary business activity, facility size and operational patterns, number of employees, and amount and timing of electricity use. To better understand the diversity of respondents within and among each sub-group, we tabulated summary statistics for various attributes.

Primary Business Activity

Manufacturing firms (38%) and government/institutional (31%) customers were strongly represented among our 144 survey respondents (Fig. 4-2). Commercial office buildings – often thought to represent a large potential source of demand responsive load – represent only 6% of PRL participants in our sample and 12% of informed non-participants.

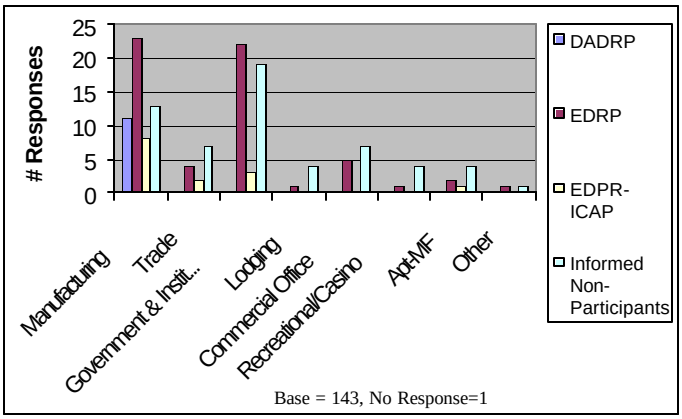


Fig. 4-2: Major Business Activities of Survey

There are some important differences in major business activities among participants in PRL programs and informed non-participants in our sample. Most notably, all DADRP respondents are manufacturing customers. In contrast, our sample of 60 EDRP-only respondents is a more heterogeneous group: 38% are manufacturing companies while 33% are government/institutional (primarily hospitals). The sample of 59 informed non-participants encompasses many market segments: 32% are government or institutional customers, 22% are manufacturing firms, 12% are commercial offices, 12% are involved in wholesale or retail trade, and 7% were multi-family apartment owners.

Facility Size

The survey respondents – both participants and non-participants, alike – spanned a wide range of facility sizes, with the median value ranging from 100,000 to 249,000 ft^2 (Fig. 4-3). Overall, survey respondents in large facilities (defined as greater than 500,000 ft^2) were more likely to be participants in a PRL program, with 79% of these respondents participating in at least one PRL program. In contrast, 71% of the non-participants occupied facilities that were less than 500,000 ft^2. Over 50% of the DADRP participants had facilities that were greater than 500,000 ft^2.

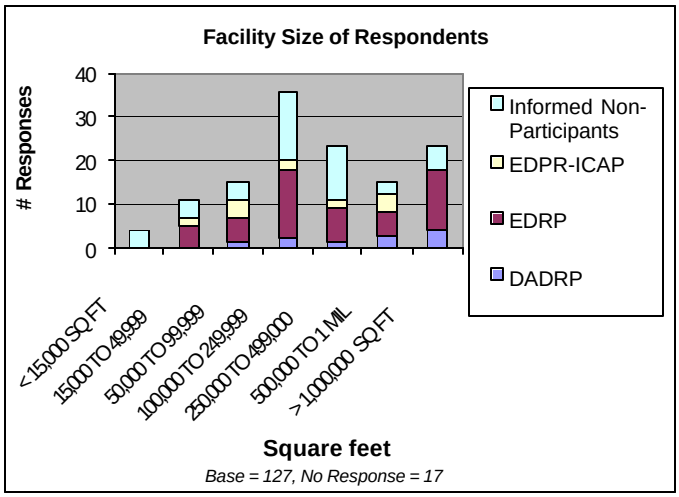


Fig. 4-3. Respondent Facility Size

Number of Employees

Most survey respondents (77%) had less than 500 full-time employees (FTE), and approximately half of these had less than 100 FTEs (Fig. 4-4). Overall, non-participants tended to have slightly fewer FTEs, compared to PRL program participants, which is consistent with the slight trend of smaller facility sizes for non-participants, described above.

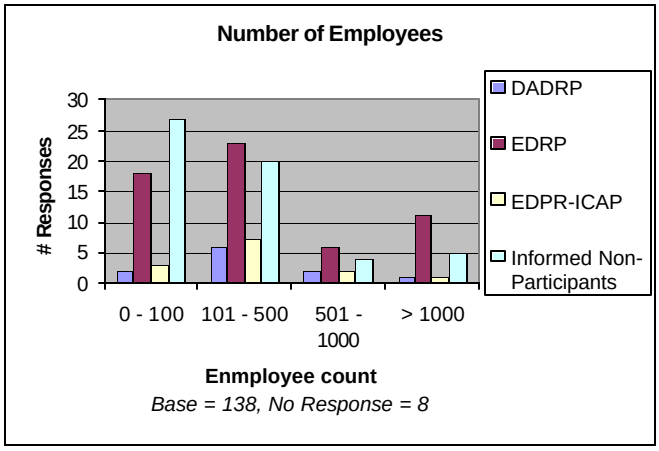


Fig. 4-4: Number of Employees of Survey Respondents

Facility Schedules

Because load curtailments often involve shifting production processes or other business activities to off-peak hours, the ability of an electricity customer to participate in a demand

response program may often depend on their business hours and whether or not they operate multiple shifts. Survey respondents were asked how many shifts are operated per day (Fig. 4-5). 60% of respondents reported operating three shifts per day. All DADRP respondents operated multiple shifts (e.g. 2 or 3 shifts), compared to 70-80% for the other three sub-groups. In contrast, about 25% of informed non-participants indicated that they only had one shift of operations in their facilities.

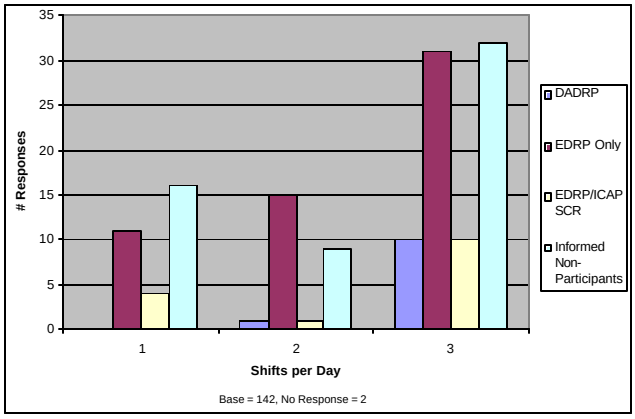


Fig. 4-5: Facility Operation Profile

Electricity Costs and Usage

Survey respondents provided information on the percent of their organization's total monthly operating costs that were attributable to electricity costs (Fig. 4-6). Electricity costs, as a percent of operating expenses, varied widely among the survey respondents with a median value

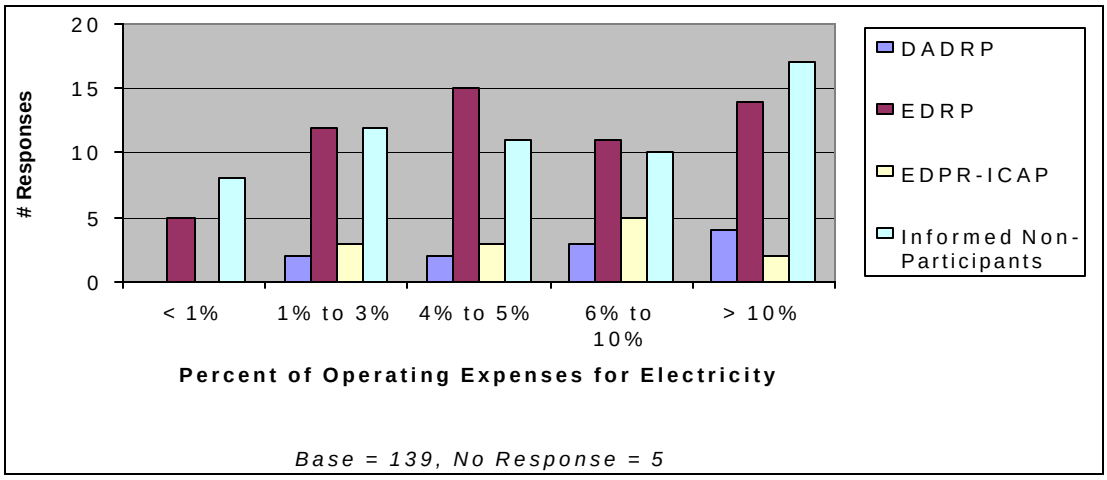


Fig. 4-6: Electricity Cost

of 5%. For DADRP participants, electricity costs tended to represent a slightly larger percentage of operating expenses than the other sub-groups, with a median value in the 6-10% range. Electricity costs are an important business expense for many customers, as indicated by fact that

about 25% of respondents reported that electricity costs represented greater than 10% of their operating costs.

Participants in a PRL program tended to have significantly higher summer peak demand than non-participants (Fig. 4-7). The median value for non-participants was 750 kW, compared to 1.7 MW for EDRP respondents, 5 MW for EDRP-ICAP respondents, and 14.5 MW for participants in DADRP. Because DADRP required 1 MW minimum load reductions, all survey respondents participating in this program were large customers, almost all of which reported peak demands greater than 5 MW. On the other hand, because EDRP and ICAP-SCR required a minimum load reduction of only 100 kW, participants' summer peak demand varied over a much wider range. Some of this variation in summer peak demand among different programs also reflects the distribution in primary business activity among participants.

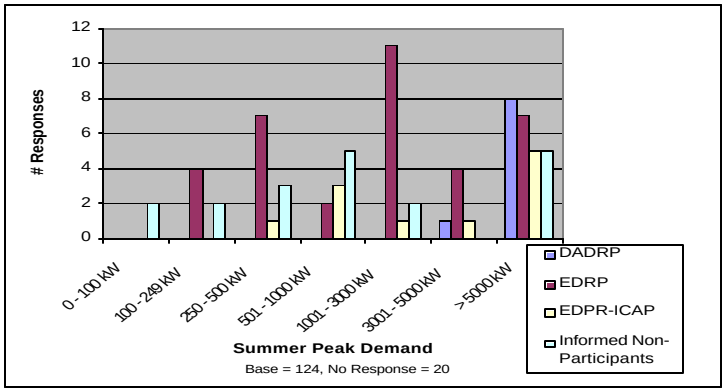


Fig. 4-7: Summer Peak Demand

Among EDRP/ICAP participants, the median summer peak demand of institutional customers was 435 kW, compared to 6,550 kW for the manufacturing customers in this sub-group. On the other hand, only a slight difference in median summer peak demand values was observed among manufacturing and institutional customers in the EDRP program (1,650 vs. 1,037 kW respectively).

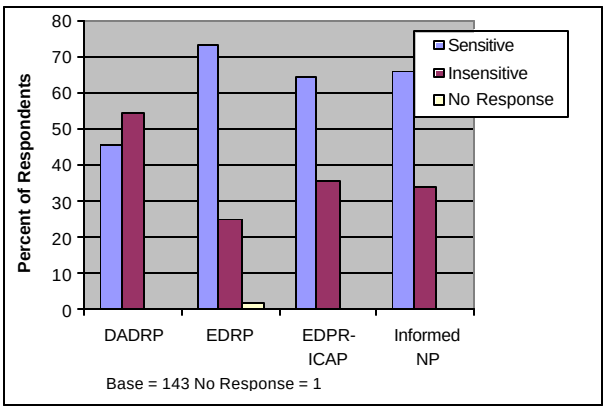


Fig. 4-8: Weather Sensitivity

With the exception of DADRP participants, most survey respondents (65-75%) described their load as temperature sensitive during the summer – which is defined as a 5% change of electricity demand resulting from changes in temperature (Fig. 4-8). This is much higher than the percentage of customers that chose to adopt the temperature-sensitive customer baseline

methodology – perhaps indicating lack of familiarity, understanding, or comfort with the temperature- sensitive CBL option. The temperature sensitivity of most respondents was largely related to air conditioning loads. The fact that DADRP participants were less temperature sensitive is a likely corollary to the prevalence of participation by manufacturing customers, whose peak loads are typically much less driven by air conditioning and more by ongoing process needs.

Survey respondents were asked what time their peak electricity usage occurred. The majority of survey respondents reported that their peak electricity usage occurs during daytime hours, with most respondents identifying the morning hours (8 AM – noon) as their peak usage period (Fig. 4-9). About 20% of DADRP participants indicated that their peak usage occurred during nighttime hours (10 PM – 8 AM).

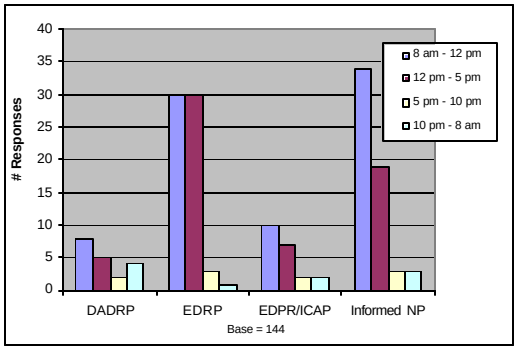


Fig. 4-9: Time of Peak Usage

Understanding Customer Participation in PRL Programs

One of the primary objectives of the customer survey was to obtain insights into factors that influence participation in PRL programs. These factors include awareness of the program, information and knowledge of program requirements in order to determine whether it is advantageous to participate, prior experience with load management programs, and perceived constraints on customer's ability to shift or curtail electricity usage driven by business or facility operations concerns.

Information and Awareness

A threshold issue for a customer's decision to participate in a PRL program is simply whether or not they are aware of the programs. Non-participants in each PRL program (e.g., DADRP, EDRP, ICAP/SCR) were asked whether they were aware of that program.

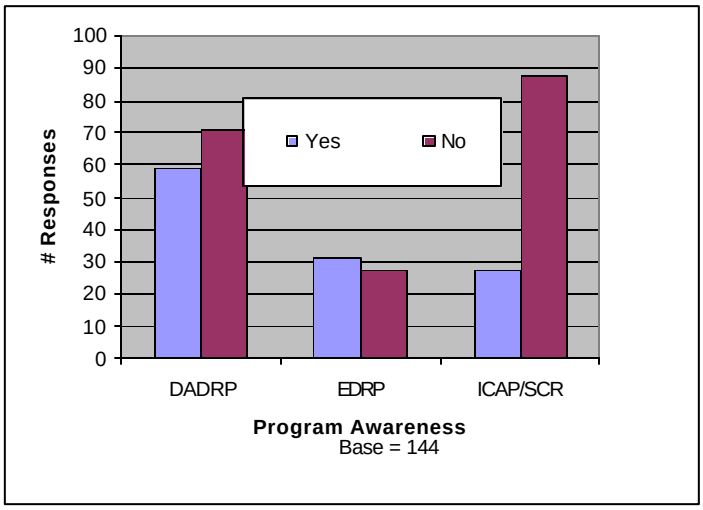


Fig. 4-10: Program Awareness

A significant number of survey respondents indicated that, in fact, they were unaware of NYISO program offerings, ranging from 45% for EDRP, 55% for DADRP to 77% for ICAP (Fig. 4-10). Given this widespread lack of familiarity with the PRL programs, additional marketing and informational workshops are clearly needed to acquaint customers with NYISO program offerings.

Informational presentations on PRL programs were sponsored during spring 2002 by various entities (e.g., NYSERDA, NYDPS, and electricity service providers). A significant portion of EDRP (50%) and DADRP (73%) participants reported that they attended these meetings (Fig. 4-11). Although the names for informed non-participants were drawn from attendance lists from these informational meetings, more than 30% of those surveyed reported that they did not attend any meetings. This might be due to the survey respondent being different from the workshop attendee.

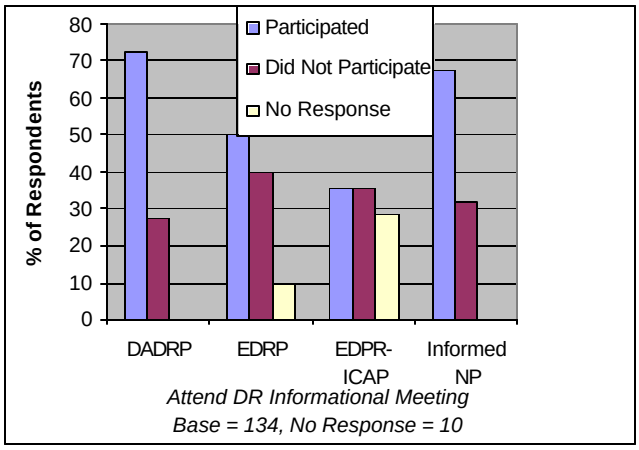


Fig. 4-11: Participation by DR Workshop Attendance

Informational and marketing brochures published and distributed by NYSERDA were major marketing tools for generating interest in PRL programs. Three different brochures were produced in 2002: NYISO Demand Response Programs, Smart Metering, and Low Cost/No Cost Demand Reduction Strategies. Table 4-2 represents the survey respondents who indicated they had received the NYSERDA informational brochure in question. Across the sub-groups, a greater percent of informed non-participants (64%) reported receiving the Demand Response Program brochures than PRL program participants (29-64% for various programs). About 30-40% of the informed non-participants reported receiving the Smart Metering and Low Cost/No Cost Strategies brochures compared to 7-22% of program participants. This

Table 4-2: Respondents who indicated receipt of NYSERDA Informational Brochures

Brochure	New Pgm. Participants	Old Pgm. Participants	Informed NP
NYISO Demand Response Programs	43%	48%	50%
Smart Metering	24%	6%	63%
Low-Cost/No-Cost Strategies	19%	10%	59%

result reflects the fact that these brochures were distributed at the informational workshops, and the informed non-participants were drawn from attendance lists from these workshops. Over 40% of new program participants reported receiving the Demand Response Program brochure. When asked about the value of the brochure on the decision whether or not to participate in NYISO demand response programs, the vast majority of participants (79%) and non-participants (71%) indicated that they found these brochures to be useful (a rank of 4 or 5 on a scale of 1-5). Thus, overall, most recipients appear to find the brochures useful, although broader and more widespread dissemination would be helpful.

Knowledge and Experience

Prior participation in utility-sponsored load management programs – such as real time pricing (RTP), interruptible rates, and time-of-use-rates (TOU) – provide customers with an opportunity to develop both the organizational knowledge and the technological capacity necessary for participation in PRL programs. Survey respondents were asked whether they previously participated in any load management program. The results indicate that customers with prior experience in one or more utility load management programs are, in fact, more likely to participate in a PRL program compared to informed non-participants (at greater than 95% confidence level). The effect was particularly strong among DADRP respondents; virtually all of these customers previously participated in at least one utility load management program, compared to 40% of non-participants and 57% of EDRP-only respondents (Fig. 4-12).

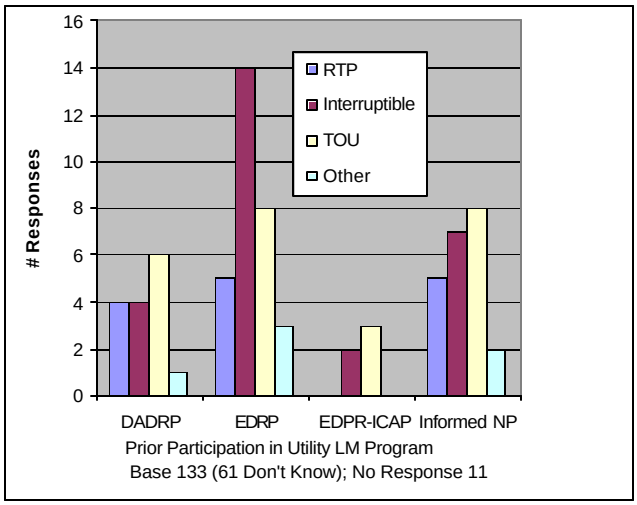


Fig. 4-12: Prior Load Management Program Participation

The presence of a designated on-site energy manager that is able to coordinate and implement load reductions may be an important enabling condition for participation in PRL programs. This issue is particularly relevant for DADRP, since a combination of a high degree of technical knowledge and organizational authority are likely needed in order to conduct the bidding activities required by the program. For many facilities, these activities would typically be

the responsibility of a facility energy manager, or some other employee with a similar level of training and authority. Consistent with this proposition, among our sample of respondents, we find that the PRL participants were more likely than non-participants (80% to 60%) to have an employee responsible for managing or procuring energy (Fig. 4-13). However, the difference is not as large as we might expect.

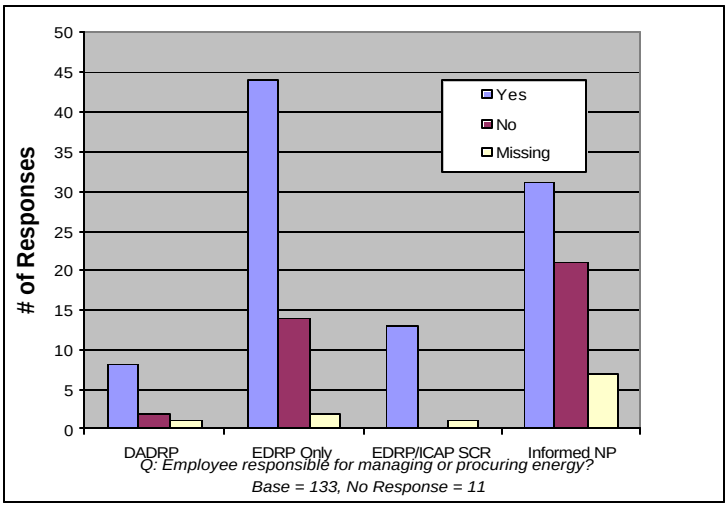


Fig. 4-13: Dedicated Energy Manager

Facility or Operational Constraints

Respondents were asked about the largest impediment to shifting load from the noon – 6:00 p.m. period to other hours of the day. Production schedules were cited as the largest impediment by the preponderance (over 75%) of the industrial customers (Fig. 4-14). In contrast, concerns about occupant comfort were cited as the biggest impediment by 80% of commercial customers, 85% of the multi-family building owners, and 55% of the institutional facilities. These findings suggest that the factors that customers view as impeding load curtailments can be

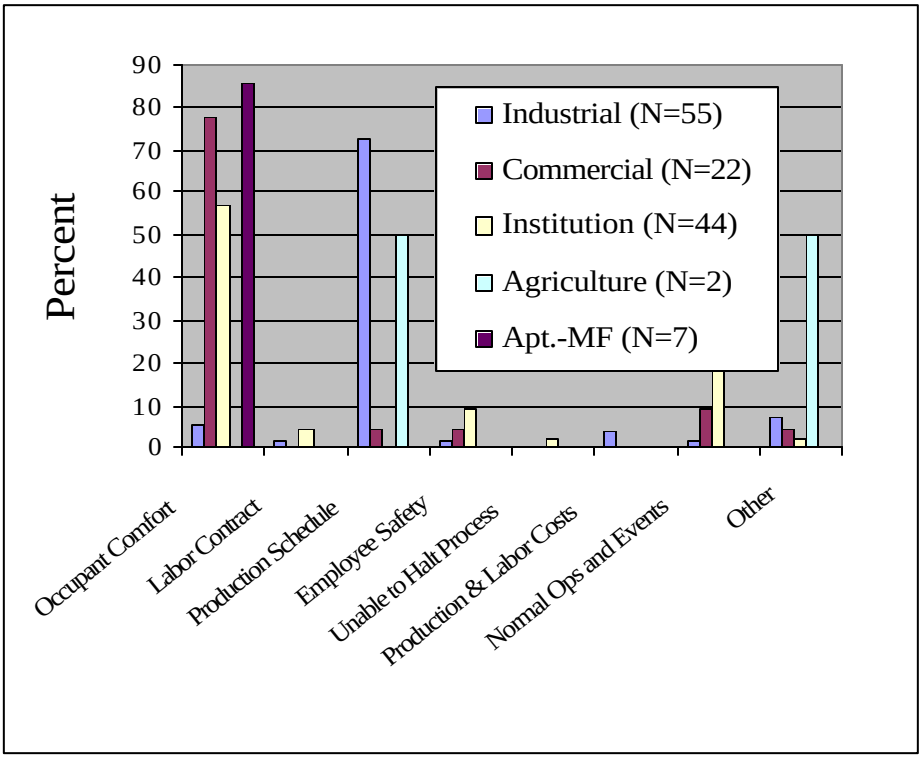


Fig. 4-14: Impediments to PRL program participation

fairly well defined based on primary business activity. Recognizing this correspondence in the design of marketing materials will help CSPs overcome customer reluctance to participate.

Load Management and Energy Efficiency Technology

HVAC or Process Controls

The existing energy management and process control infrastructure is a key element for effective load reduction strategies. HVAC equipment and industrial processes can be remotely controlled and scheduled while operations can be monitored and supervised to varying degrees depending upon the sophistication of the controls and automation technologies. It is difficult to fully assess the capability of the facility's controls infrastructure or its suitability for load management strategies without a site audit. Based on self-reports by survey respondents, between 65 and 70% of the DADRP, EDRP, and non-participants reported using HVAC or energy management and process controls systems on a facility or building-wide basis (Fig. 4-15). In contrast, about 35% of the EDRP/ICAP respondents indicated that they used building-wide HVAC or process control technology. Based on these survey responses, it is not possible to determine whether these control systems are capable of supporting cost-effective dispatching of load reduction strategies that would achieve a higher level of performance compared to manual control. However, most survey respondents performed load reductions manually which suggests that the existing control infrastructure configuration was compatible with the load reduction strategies that participants chose to carry out. Resolving that incompatibility may be a low cost means of increasing participant performance.

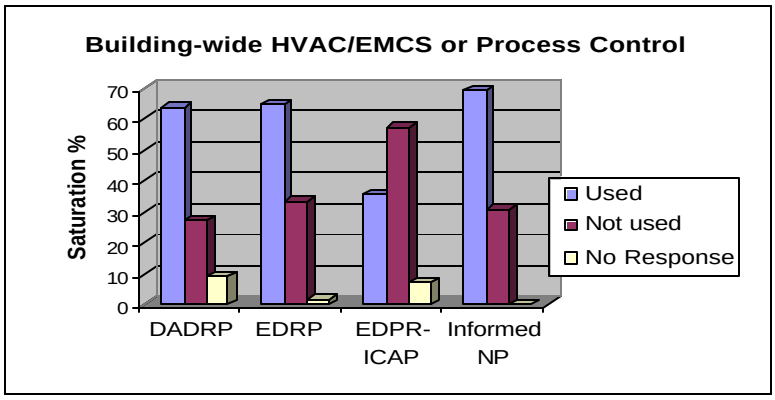


Fig. 4-15: Use of Control Technologies to Respond to PRL Events.

Fig. 4-16 shows the saturation of building-wide HVAC or process control technology by business type. Based on customer self-reports, saturation ranges from 0% for multi-family respondents to 100% for customers in wholesale and retail trade. Manufacturing is the second lowest with 43% saturation, which is characteristic of established heavy industry as opposed to new high-tech manufacturing plants, which are highly automated. Customers in government, institutional, health, lodging facilities, commercial office buildings, and recreational facilities reported saturations of building-wide HVAC controls of around 75-80%.

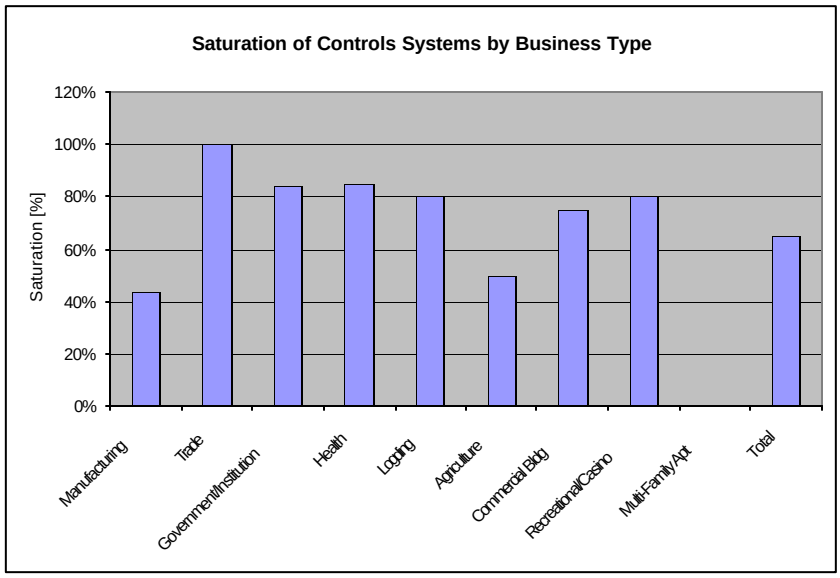


Fig. 4-16: Control Technology Saturation by Business Type

Access to Real-Time Metering, CBL, Curtailment Performance, or Wholesale Electricity Prices

An hourly interval meter is required for PRL participation. Access to that meter in real-time or near real-time can be helpful for PRL program response, especially for programs like DADRP and ICAP/SCR that impose penalties for noncompliance. Some customers reported installing web-based energy information systems (EIS) that provide information on customer baselines (CBL) prior to a load curtailment event. These EIS provide customers that do not already have an integrated metering and EMCS with the option to view consumption data on a day-after or near real-time basis.

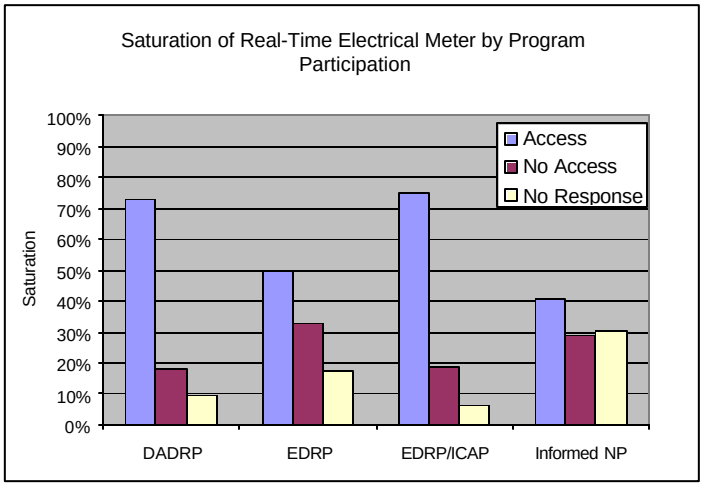


Fig. 4-17: Saturation of Real-time Metering

Fig. 4-17, 4-18, 4-19 and 4-20 show the saturation of real time or near real-time electric metering, CBL monitoring, curtailment event performance, and wholesale electricity price monitoring systems among program participants. Survey respondents reported that access to electrical meter data achieved the highest saturation levels among the four technologies categories investigated. Access to interval meter data was accomplished through a web-based product offered by the CSP or LSE or available through the customer's facility automation system entered meter readings directly into the system. The web-based products typically display historical and most current usage data as recorded on the meter. CBL products are generally web-based and display CBL on an hourly basis superimposed onto load data. Saturation of both CBL and curtailment event performance technology was in the 10% to 30% range suggesting that the majority of the customers performed curtailments without immediate feedback on their performance.

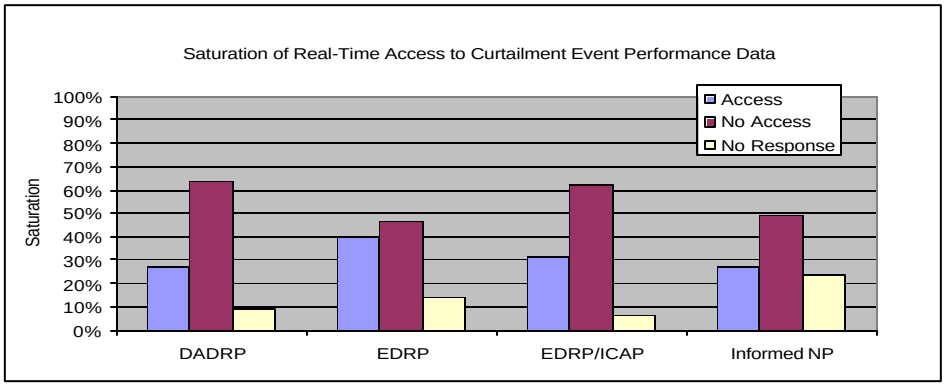


Fig. 4-18: Access to Real-time Performance Data

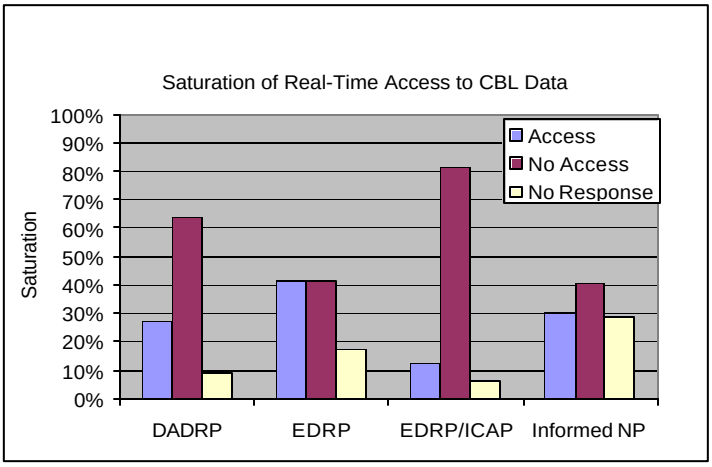


Fig. 4-19: Access to CBL Data

It is surprising that few of the jointly subscribed EDRP/ICAP program participants reported using the real time CBL and/or curtailment event performance tools given the penalty clauses of the ICAP/SCR program. Nevertheless, as discussed in Chapter 5, EDRP/ICAP participants managed a high degree of performance relative to their subscription level suggesting that they either used onsite generators that delivered a predictable load reduction, or that they shut off industrial processes, which provided a predictable and firm load reduction.

Wholesale electricity prices are provided by the NYISO and accessible on the NYISO website. To the degree that customers have Internet servers at their facility, they have access to day-ahead market electricity prices. The saturation levels for near real-time access to electricity prices as shown in Fig. 4-20 is probably more indicative of customer's general knowledge regarding the accessibility of electricity price information rather than the actual ability to obtain the data.

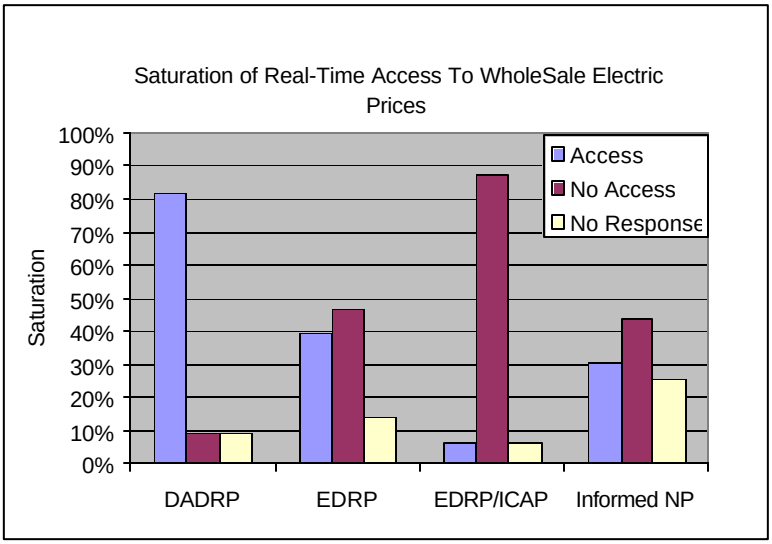
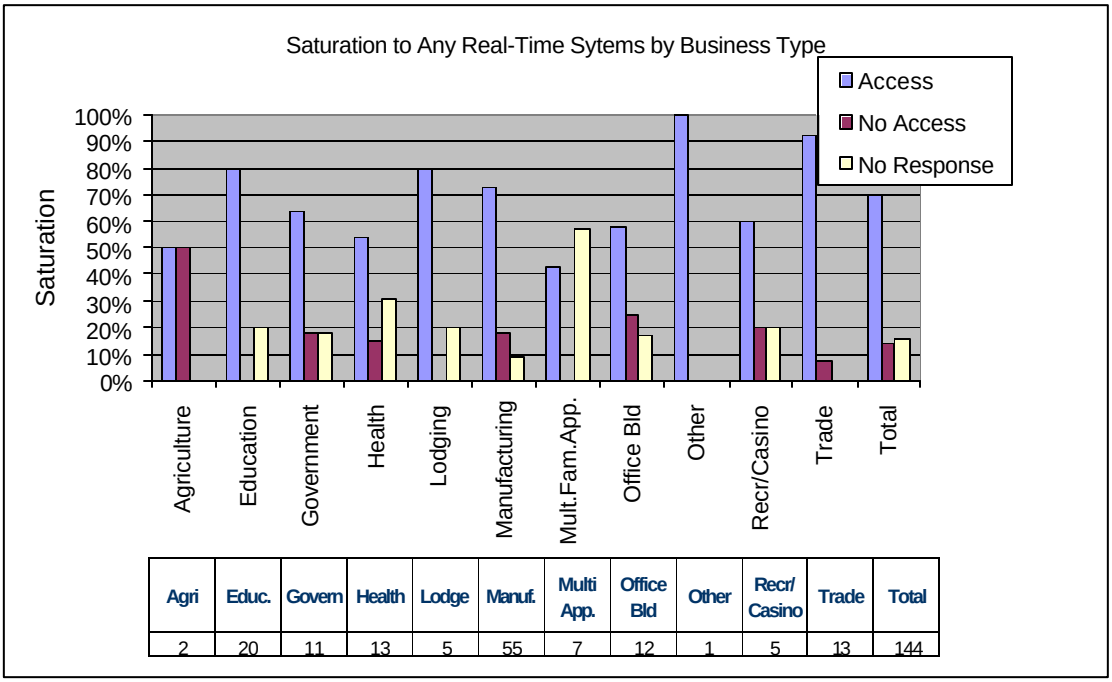


Fig. 4-20: Real-Time Access to NYISO Electricity Prices

DADRP participants would be expected to monitor wholesale electricity prices in order to determine their bid price offers. As a consequence, their saturation level for access to wholesale electricity prices is the highest of all other program participants. The lower saturation



Agri	Educ.	Govern	Health	Lodge	Manuf.	Multi App.	Office Bld	Other	Recr/ Casino	Trade	Total
2	20	11	13	5	55	7	12	1	5	13	144

Fig. 4-21: Real-Time Saturation by Business Type

level for the EDRP and EDRP/ICAP participants could reflect the fact that customers do not have a direct need for this price information as they are notified by the ISO, LSE, or CSP when there is a system emergency condition that requires load curtailments.

Aggregated saturation levels of real- or near real-time technologies are shown by business type in Fig. 4-21. Overall, for most market sectors, saturation levels are in the 70-80% range with the exception of agriculture and multi-family apartment buildings (~50% saturation), although sample sizes are small.

PRL Audit Results: Barriers to Participation in DADRP

While participation in the NYISO's emergency (EDRP) and capacity (ICAP/SCR) programs increased during 2002, this enthusiasm has not translated into increased bidding in the day-ahead energy market. In fact, bidding activity in the DADRP was lower in summer 2002 compared to summer 2001, despite an increase in program registrations. A primary objective of the customer research initiatives included in the 2002 PRL program evaluation was to characterize and quantify the factors that act as barriers to participation in DADRP. This section draws primarily on in-depth interviews that were conducted with a sub-set of 35 customers (i.e., PRL audit) to characterize better the various barriers to customer participation in DADRP.

Low Awareness Levels for DADRP program

Awareness levels of the DADRP program are low, even among those registered in other NYISO programs. Table 4-3 shows DADRP awareness levels for EDRP participants and informed non-participants. It is notable that a smaller percentage (39%) of EDRP participants are aware of DADRP compared to informed non-participants (53%); the difference is statistically significant at a 15% confidence level. Apparently, customers are being recruited to specific programs with very little selling of the PRL portfolio, which suggests that, at least with respect to awareness levels, the potential "training ground" boost that EDRP participation was expected to provide to DADRP is not being

Table 4-3. DADRP Awareness Levels

	Yes	No	Totals
Informed NP	31 *53%*	28 *47%*	59 *100%*
EDRP	28 *39%*	43 *61%*	71 *100%*
Totals	59 *45%*	71 *55%*	130 *100%*

q52: Are you aware of the NYISO DADRP Program?
a) "EDRP" also includes those in EDRP in combination with ICAP
b) There were no responses from ICAP Only participants.

widely exploited at present by load serving entities (LSE) marketing the program. Informational and marketing efforts should target the program element to which the customers seem to be best matched. However, customers should be made aware of the full range of participation opportunities so that they can use their initial experience to gauge their capability of participating in other programs in the future.

Primary reasons given for not participating in DADRP

Respondents that were aware of the DADRP were asked to indicate their primary reason for not participating in the program. Inadequate compensation for perceived risks (35%) and inability to shift or curtail usage (35%) were the primary reasons given by DADRP non-participants overall (Totals column in Table 4-4). Inadequate knowledge of program requirements was mentioned only half as often (17%). Surprisingly, and contrary to popular belief, the existence of a penalty for non-performance was not cited as nearly as important – only 6% of all respondents so indicated.

Table 4-4. Primary Reasons for Non-Participation

	Risks or Payments	Can't Shift Usage	Inadequate Knowledge	All Other	Totals
Informed NP	9 *29%*	19 *61%*	1 *3%*	2 *6%*	31 *100%*
EDRP	13 *41%*	3 *9%*	10 *31%*	6 *19%*	32 *100%*
Totals	22 *35%*	22 *35%*	11 *17%*	8 *13%*	63 *100%*

q53: Which best describes your primary reason for not participating in the DADRP Program?

a) "EDRP" also includes those in EDRP in combination with ICAP.
b) There were no responses from ICAP Only participants.
c) "Penalty is too severe" was cited only 4 times. It is counted in All Other

There were some dramatic differences in the reasons offered by EDRP participants relative to those of informed non-participants. About 58% (19 of 31) of the informed non-participants indicated that operational and business constraints on their ability to shift load were a primary reason for not participating in DADRP. About half that many (9 out of 31) cited inadequate compensation levels for perceived risks as the main barrier. In contrast, EDRP participants, for whom doubts about ability to respond to prices are presumably resolved, most often cited inadequate compensation for perceived risks (41%), followed closely by inadequate knowledge of DADRP program requirements (33%). Apparently, non-participants do not believe

that they can shift usage, and therefore dismiss participation out of hand, while EDRP participants are more concerned with the risks associated with what and how they are paid. Additional insight into this question comes from other survey responses, as discussed below.

Customer's relative confidence level in performing activities necessary to participate in DADRP program

Participation in DADRP requires both more active involvement in their electricity usage, as it related to business activity, and knowledge of day-ahead energy markets. Participants must decide whether or not to submit load reduction offers in the day-ahead market and determine the bid strike price at which they are willing to curtail load. PRL audit respondents were asked to rate their comfort level on a scale of 1 (low) to 5 (high) in performing the following activities:

- Creating a load curtailment plan to meet a specific kW reduction target;
- Monitoring day-ahead energy prices to determine whether to bid; and
- Determining at what price to bid.

Table 4-5: Information/Knowledge Barriers

	Creating Curtailment Plan		Monitoring Energy Prices		Determining Bid Prices	
	DADRP	**Other**	**DADRP**	**Other**	**DADRP**	**Other**
Not Comfortable	1	6	1	12	1	17
Comfortable	9	14	9	7	9	3
Total	***10***	***20***	***10***	***19***	***10***	***20***

Respondents with a score of three or higher were characterized as being comfortable, those with lower scores as not comfortable. Table 4-5 compares the comfort levels for each activity for 10 DADRP participants and other respondents (19 of 20 are in EDRP or EDRP/ICAP). Ninety percent of DADRP respondents report that they are comfortable performing all three activities, creating a curtailment plan, monitoring energy prices, and establishing a bidding strategy. In contrast, while 70% of non-DADRP respondents are comfortable preparing a load curtailment plan, only 35% are comfortable monitoring day-ahead energy prices, and only 15% report that they are comfortable determining prices at which to bid load curtailments.

These results suggest that EDRP/ICAP participants need additional information, education, and training on preparing and executing bidding strategies in day-ahead energy

markets before they will join DADRP. These findings may also indicate that currently most customers are more comfortable participating in PRL programs where they only have to create a curtailment plan, since putting it into action is determined by a third party (i.e., NYISO).

Many customers report high minimum bid price thresholds to participate

PRL audit respondents were asked questions about the minimum price at which they would submit load curtailment bids as well as the amount and duration of a load curtailment. Bid prices ranged between $0.05 to $5.00/kWh, with mean and median values of $0.87 and about $0.50/kWh respectively (Fig. 4-22). About 80% of the 19 respondents indicated that their minimum bid prices was $.20/kWh or higher.

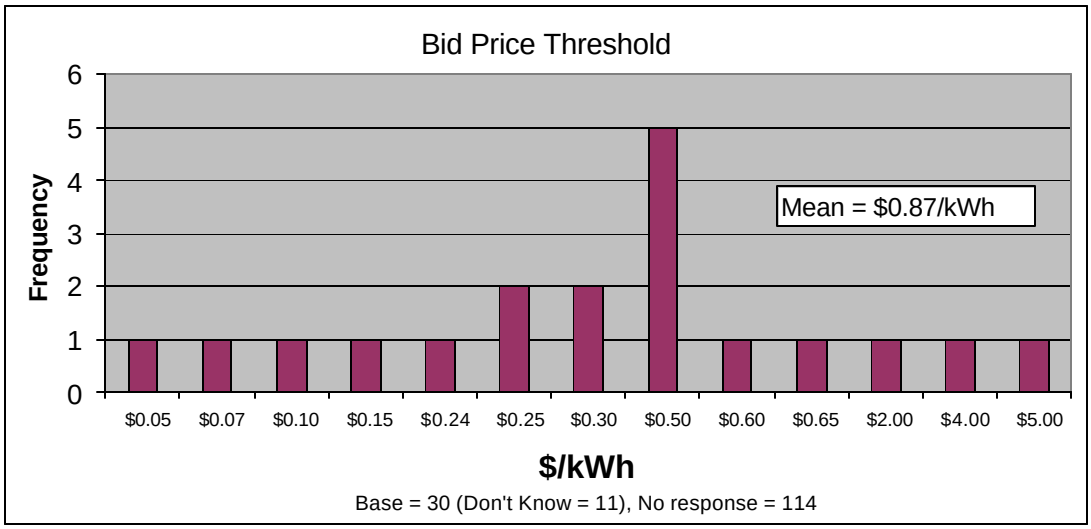


Fig. 4-22: Bid Price Thresholds.

The bid threshold results create a conundrum. The average bid price threshold of $0.87/kWh stated by respondents is over 50% above the EDRP floor price (which in almost every case is also the actual payment level for EDRP curtailments). But, participants in DADRP should require a lower premium than EDRP since curtailments are in effect announced a day in advance, and customers control under what circumstances they can be called upon.[2] However, recall that customers indicated that the major deterrent is uncertainty about the characterization of the NYISO's DAM prices that constitute the benefit stream from DADRP bidding. It may be that this uncertainty is reflected in the relatively high bid price thresholds.

Role of Enabling Technologies

DR-enabling technologies can be grouped into the following categories:

- Electrical metering, monitoring, and information systems,
- Control and automation systems, and
- On-site generation systems.

Each technology, either directly (generation) or indirectly (via improved control) facilitates load management strategies. Metering at the service entrance or end-use sub-metering combined with an appropriate representation of metered data are the most basic services available for effective load management strategies. Process control and energy management and control systems allow the automation of load reduction measures from a central location in the facility. They improve the accuracy and timing of load management at low or no labor cost. The investment requirements of controls, automation, and generation technology vary greatly with the size of the facility and the particular technology of interest.

Some have asserted that the presence of energy information tools and enabling technologies is a necessary condition to elicit sustained customer participation in PRL programs. Such contentions give rise to proposals to increase the floor on guaranteed payment levels for curtailments in order to pay for these technology investments. Others argue that public benefit program funds should be directed at such investments to reduce barriers to participation. Accordingly, the customer survey and PRL audit sought to help clarify the role of technology in demand response program participation.

PRL audit respondents were asked a set of questions about technologies that enable load curtailments/reductions: whether or not respondents performed or received feasibility assessments, major factors that contributed to their decision not to invest in the technologies under consideration, and respondents' perception of other benefits of DR enabling technologies. Of the 22 PRL audit respondents that answered these questions, most reported that they had considered and rejected 1 or 2 enabling technologies. Respondents also reported that they considered or were approached relatively frequently by load aggregators/vendors to install onsite generation equipment (15) or interval meters (12), and that these overtures were mostly rejected. The later result is understandable as an interval meter is required for participation. Asked to

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[2] This is in contrast to NYISO DAM LBMP's being higher than their real-time equivalents because of the risks of committing a day ahead, and one of the reasons why DADRP should be encouraged as it will tend

indicate acceptable payback periods for investments in equipment or controls to facilitate load curtailment, approximately 80% of the respondents indicated that load management investments would have to pay back in three years or less for their firm to be interested. This may explain why DG investment opportunities were eschewed.

PRL audit respondents were then asked to rate the value on a 1 to 5 scale (where 1 is low and 5 is high) of other ancillary benefits that have been identified for DR enabling technologies. Respondents were provided with a table that included enabling technology and list of possible ancillary benefits. Energy information tools ranked highest on average (3.5), while customers average values ranged between 2.2 - 2.9 for other DR enabling technologies: upgrading on-site generation for duel-fuel capability or improved switch gear, enhanced EMCS system, load control, and interval meters with two-way communications (Table 4-6). These ratings suggest that customers do not recognize and/or have not been convinced that DR enabling technologies have significant "spill-over" benefits that can help them manage their businesses better and/or reduce their energy costs.

Table 4-6: Indicated Value of DR Enabling Technology

Technology	Benefit	Mean
1. Interval meters with two-way communication	Better manage peak energy and demand charges with day-after access to facility interval data	***2.78***
2. Load Control	Shed load and/or initiate on-site generation, in order to reduce demand charges	***2.87***
3. Upgrade switchgear for on-site generation	Increase load mgmt. flexibility to modify load profile for more desirable energy procurement	***2.61***
4. Upgrade on-site generation for dual-fuel capability	Fuel flexibility to mitigate fuel price volatility	***2.23***
5. Enhanced energy management or control system	Ability to schedule and/or automate load mgmt., and reduce labor for facility operations, increase reliability to integration with maintenance procedures	***2.97***
6. Energy information tools	View individual and mulitiple facility interval electricity data, increase understanding of loads for lower cost energy procurement	***3.47***

Given the relatively high costs of various technologies that facilitate automated load response compared to expected benefits, if such technologies are critical to participation, then market intermediaries (e.g., load aggregators, controls vendors, performance contractors), perhaps supplemented by public benefit investment funds, will be required to fully develop the demand-response potential. However, the survey results indicate that technology alone is not sufficient. In

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to reduce that spread.

addition to providing financial incentives to buy down the cost of enabling technologies, administrators of public benefit funds need to develop a broad set of informational/educational tools to help make the "business case" for DR investments to senior managers and educate customers on ancillary benefits that can result from installation of DR enabling technology.

Expected Participation Effects of Changing DADRP Rules

Non-participating DADRP customers were also asked whether various changes in DADRP program design or rules (e.g., ability to submit bids to curtail loads on daily, weekly or monthly basis, reduced penalties for non-compliance, information on actual Customer Baseline Load (CBL) prior to submitting bid) would change their decision regarding participation. A relatively small number of respondents (16 or 26%) indicated that they would be more likely to participate in the DADRP if their preferred approach to submitting bids were adopted. Most respondents were unsure (48%) or indicated that it would not influence their choice not to participate (26%) (Fig. 4-23). Survey respondents unmistakably have indicated in many ways that they are uncomfortable with bidding into DADRP. It is not yet possible to sort out the relative influences of factors they cited, although it seems clear that a greater understanding of how customers make productive decisions is needed in order to refine programs so that they are in accord with electricity valuation. Moreover, someone will have to take the initiative to develop educational materials and tools to help customers develop a sufficient understanding or market price formation so that customers can develop and execute a bidding strategy.

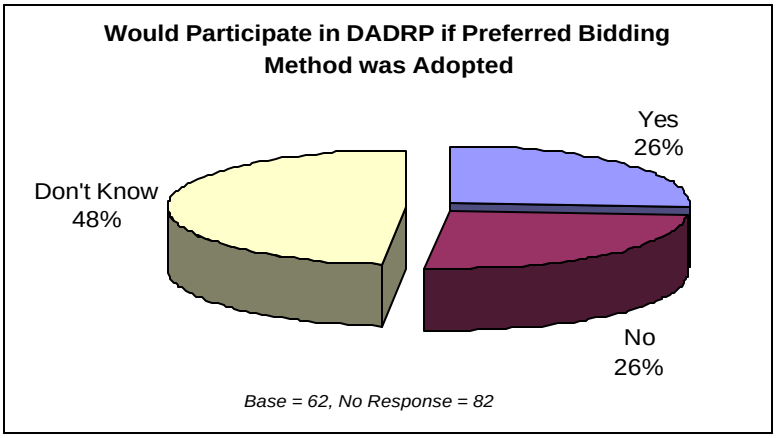

Fig. 4-23: Bidding Method Participation Decision

Summary

We have identified the following factors that in combination contribute to the relatively low participation rates in the DADRP program. These factors include:

- low customer awareness levels;

- inadequate knowledge of DADRP program requirements;
- many customers' belief that operational or business constraints severely limit their ability to shift or curtail loads;
- customer perception that the potential benefits are inadequate to compensate for the perceived risks initial costs;
- customer information and knowledge gaps related to development of effective load curtailment and bidding strategies;
- customer self-reports of high minimum bid price thresholds (>$200/MWh);
- support among some customers for more flexible bidding processes; and
- customer perception that additional benefits of installing DR enabling technologies are limited.

The results of the PRL audit surveys provide considerable insight into why customers are willing to undertake load curtailments under seemingly more restrictive conditions (e.g., shorter notice for both EDRP and ICAP/SCR and a potentially harsh noncompliance penalty for ICAP/SCR) but eschew DADRP bidding under conditions that are analogous to those of successful RTP programs.

Customer EDRP Subscription Levels and Performance

In this section, we analyze factors that may influence EDRP subscription levels and actual event performance drawing from the customer survey results. In particular, we conduct exploratory analysis of varying load reduction strategies, impact of facility size, level of automation in load response, and the extent of energy efficiency investments.

For this analysis, we define a performance index, called the Subscribed Performance Index (SPI), which is the ratio of load reduction actually delivered during events to the load reduction nominated by the customer when they subscribed to the program (see Chapter 5 for more detailed discussion). Formally, SPI is defined as:

$$SPI = (P_{avg} / P_{sub}) \cdot 100\% ,$$

where

$$P_{avg} = \frac{1}{N} \sum_{N}^{t=1} (CBL_t - P_{actual,t})$$

and

N = the number of hours per curtailment event,

$P_{actual,\,t}$ = the facility demand in hour t [MW],

CBL_t = the customer baseline [MW], and

P_{sub} = the load curtailment capability the customers indicated upon subscription.

EDRP Performance Affected by Load Reduction Strategies

Table 4-7 summarizes the subscribed load reduction and actual performance during summer 2002 EDRP events for the 83 program participants that responded to our customer survey (this group includes customers that participated either in EDRP only or in EDRP and ICAP/SCR). The majority (69) of these customers curtailed usage by reducing loads (without utilizing backup or emergency generators). For this group, it is important to note that subscribed and actual performance levels are influenced by the distribution of individual customer results. Most customers reduced their usage by <1 MW, while one large multi-site customer accounted for 92 MW of load reduction (or more than 50% of the load-only subscriber pool).

The average SPI for the load reduction-only customers is 66%, which is surprisingly high compared to the average SPI of only 16% for the 10 customers that relied on onsite generation. Overall, among the population of EDRP participants that utilized onsite generators, SPI values were higher than load reduction-only participants, indicating more reliable performance (see Chapter 5 for more information). Note that several of the 10 customers did not perform during the July 30 and August 14, 2002 events, so the sample size is small).

Table 4-7: Subscription and Performance of Surveyed EDRP Customers

Load Reduction Method	N	Subscribed Load Reduction [MW]				Avg. Performance [MW]	SPI
		Median	Min	Max	Total		
Load-only	69	0.3	0.024	92.0	274.0	179.5	66%
Load + onsite generation	4	1.15	0.5	30.0	32.8	18.0	55%
Onsite Generation only	10	1.1	0.3	3.0	13.4	2.2	16%
Total	**83**				**320.2**	**199.7**	**62%**

EDRP Performance vs. Size of Customers' Facilities

In Fig. 4-24, we show the range in SPI values for customers of different size ranges, as expressed by floor area. Smaller facilities, those between 15,000 ft^2 and 500,000 ft^2 had similar

SPI values, of about 35%. Average SPI values increase dramatically to 50-65% for facilities larger than 500,000 ft^2.

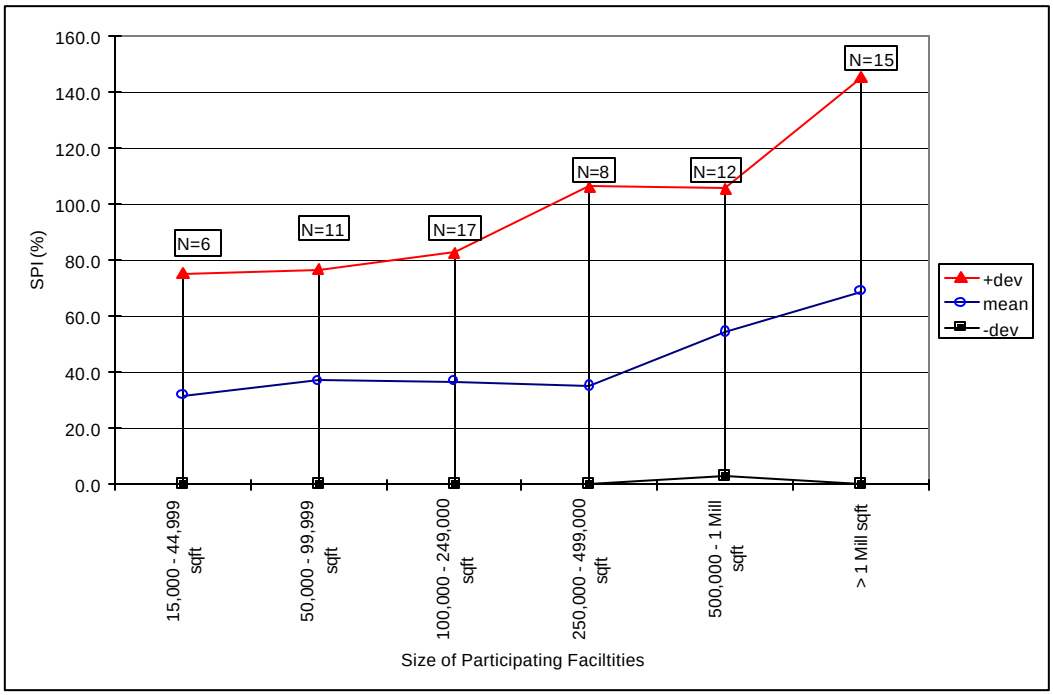

Fig. 4-24: EDRP Performance by Size of Facility Measured in Floor Area

EDRP Performance vs. Level of Automation in Load Response

As part of the survey, customers were asked whether they planned to implement load curtailments manually, semi-automated, or fully automated, with accompanying descriptions of these categories (survey question #28). We hypothesized that participants that implemented load curtailment actions through a semi-automated or fully automated approach were more likely to perform at a higher rate to meet their subscribed load reduction targets than participants that relied on manual approaches.

In Table 4-8, the average individual SPI is defined as the mean value of individual SPIs for each group (manual vs. automated load response), whereas the average overall SPI is defined as the aggregate actual performance divided by the aggregate subscribed MW load reduction for each group. Although the mean values for the sub-group that utilized automated load management strategies are higher compared to group that relied on manual load curtailments (59% vs. 37%), the results are not statistically significant.

Table 4-8: Result of Hypothesis Test on Effect of Automation

Load Management	N	Subscribed Load Reduction [MW]	Actual Performance [MW]	Average Individual SPI [%]	Average Overall SPI [%]
Manual	60	271.9	161.7	36.9	59.5
Automated (semi and fully)	15	46.7	37.0	59.2	79.2

Note: Row for automated load management consists of 13 semi-automated, one fully automated and one with both semi- and fully automated load management. See footnote definition of fully and semi-automated load management[3]. (P-value = 0.14)

EDRP Performance vs. Energy Efficiency Investments

As part of the survey, customers were asked to check off various types of high-efficiency equipment in that they had purchased within the last five years to reduce electricity costs (survey question #31). The hypothesized relationship between customer investments in energy efficiency and EDRP performance is complex. On the one hand, customers that have undertaken significant investments in high-efficiency equipment may have less capability to reduce their usage during system emergencies (e.g., flatter load shape, less inefficiencies in usage). On the other hand, we assume that customer facilities with higher energy efficiency investments have better process control or energy management system infrastructures and a higher awareness of their consumption patterns, which would tend to improve their performance characteristics. On balance, we hypothesized that significant investments in high efficiency equipment would be correlated with improved customer load curtailment performance. We defined "significant" investment in energy efficient equipment as survey respondents that listed three or more categories of high-efficiency equipment purchases (i.e., "energy efficiency upgraders"). Customers that checked less than three categories were classified as "non-energy efficiency upgraders."

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[3] Definitions:

semi-automated: Requires the use of EMCS (energy management and control systems) to invoke demand response measures. This could include:

a. remote resetting of one or many thermostats
b. remote turn off of equipment or processes
c. invoking a script or macro established in the EMCS that in turn resets thermostats or turns off equipment or processes

Typically, the facility operator would be notified by a phone call, page, email and then would go to the EMCS to invoke above measures.

fully-automated: Measures that require NO human intervention to be invoked. This could include: direct load control, CSP invokes load reduction, or load reduction measures are pre-programmed in an EMCS and then invoked by an email or pager from CSP without the intervention by facility operator.

We tested the following hypothesis:

Relative to other participants, firms that have upgraded or invested in new load shifting technology in the past 5 years are more likely to have performed at a higher rate during 2002 EDRP event.

Average SPI values tend to increase among customers that listed additional categories of upgrades or purchases of high efficiency equipment (Fig. 4-25), although we found the results not to be statistically significant (Table 4-9).

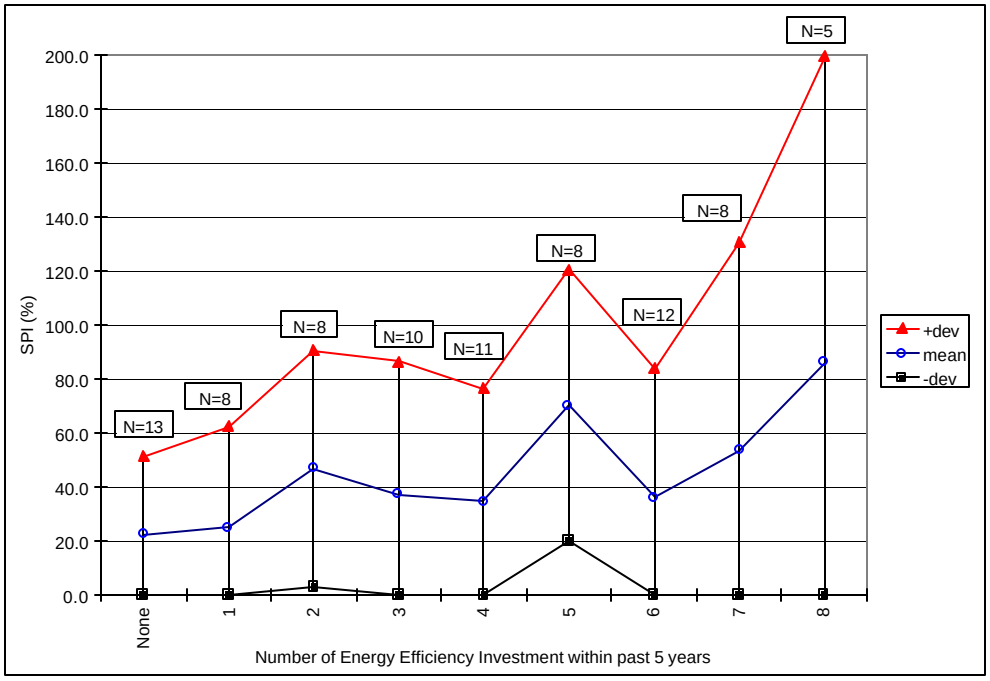

Fig. 4-25: EDRP Performance by Number of Energy Efficiency Investments during the Past 5 Years

Table 4-9: Result of Hypothesis Test on Effect of Energy Efficiency Investments

Investment	N	Subscribed Load Reduction [MW]	Actual Performance [MW]	Average Individual SPI [%]	Average Overall SPI [%]
Non-investors	56	149.8	68.2	46.9	45.5
Investors	27	170.9	131.5	31.5	77.0

Relationship between EDRP Performance and Specific Load Curtailment Strategies

We also conducted exploratory analysis of the relationship between customer performance during EDRP events and the specific load management strategies that customers employed based on a list of ten actions checked by survey respondents. We hypothesize that more predictable performance can be achieved by utilizing on-site generators or by shutting off entire industrial processes compared to other strategies that involve various buildings-related measures (e.g., turn off or dim lights, increase indoor temperatures, reduce plug loads).

We grouped customers into three classes of performers: high, medium, and low performing customers, defined as:

- Low performer: 0% = SPI <33%
- Medium performer: 33% = SPI < 66%
- High performer 66% = SPI

Fig. 4-26 shows the frequencies of load management strategies used for the low, medium, and high performers. Customers within the high and medium performer groups utilize the 10 load management tasks almost equally often. The low performers indicate a high relative contribution of three strategies: 1) increase indoor temperature, 2) turn off or dim lights, and 3) alter major production processes. Two of these strategies ("turning off or dim lights" and "increasing indoor temperature"), if not controlled centrally, require the active participation of facility workers and building occupants, who need to be informed about the emergency and when it occurs. For low performers, the frequency of communication with employee/occupants strategy is significantly less than that of the thermostat reset or light dimming strategy. This could be indicative of a lack of notification and/or awareness of building occupants among this group, which are linked to the effectiveness of these strategies.

The high performer group utilizes a broad range of load reduction strategies. No one single strategy is predominant among our sample, which reflects the heterogeneity of EDRP program participants and load reduction strategies among commercial and industrial customers.

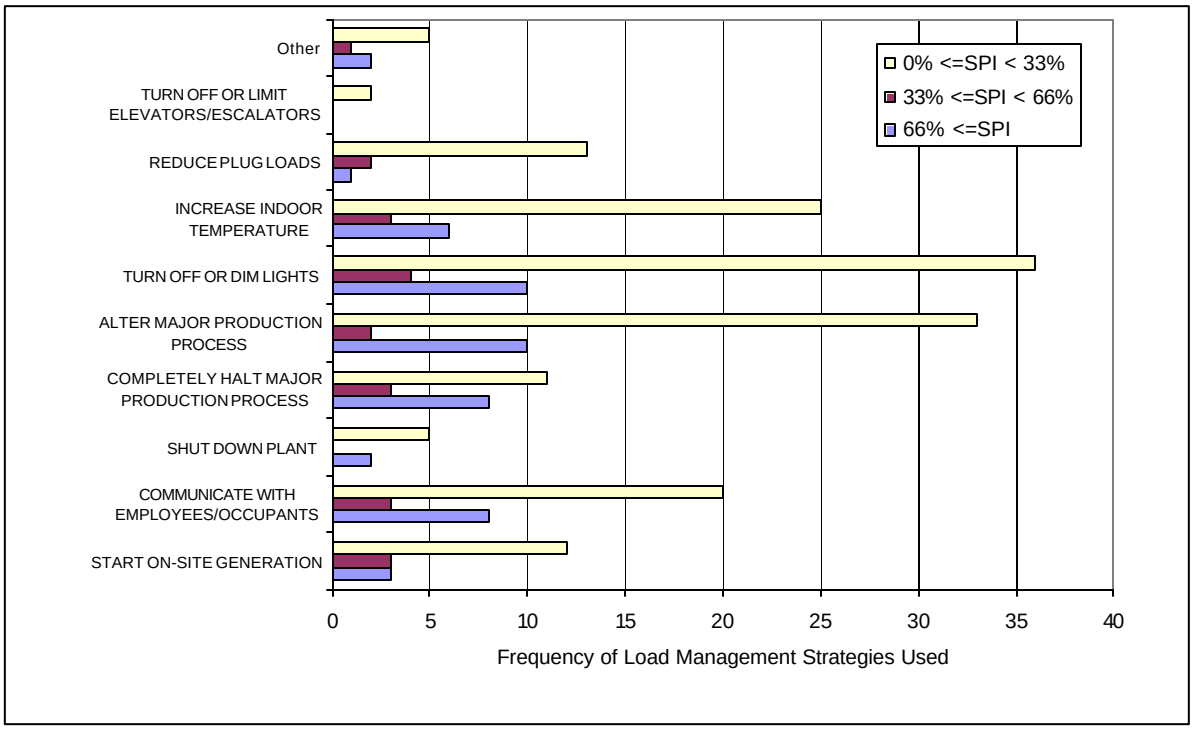

Fig. 4-26: Load Management Strategies Used by high, medium, and low Performance Groups

Factors Affecting Firms' Decisions to Participate in NYISO's Electricity Price Responsive Load Programs and their Valuation of Program Features

Introduction

As in the 2001 PRL program evaluation, we have collected data through a customer survey to gain a better understanding of why some customers participate in the NYISO PRL programs and others do not. To understand enrollment decisions, we need to study the characteristics of participants in order to find patterns that lead to identifying good candidates for program participation and to find out how customers value alternative program designs.

Through a statistical analysis of the data collected in Part I of the Customer Acceptance Survey, this chapter explores those customer characteristics, and actions by New York state agencies, market participants, and other institutions, that affected a firm's decision to participate or not to participate in NYISO's PRL programs this past summer (2002). This analysis is concerned with the "revealed" preferences of customers regarding their decisions to participate in the NYISO programs. Analysis of "revealed" preferences is the mainstay of much economic analysis of consumer and firm behavior (McFadden, 2001). For the 2001 evaluation (Neenan Associates, 2002) it was only possible to model firms' binary decisions to participate in EDRP vs. no PRL program participation. This year, due to an expanded survey instrument design, we are able to model more complex choices: the decision to participate in DADRP and one or both of the PRL emergency programs (EDRP and/or ICAP/SCR), the decision to participate in EDRP or both emergency programs, or the decision not to participate in any PRL program.

Part II of the Customer Acceptance Survey involved a "conjoint" survey designed to solicit customers' "stated" (in contrast to "revealed") preferences for different program characteristics or features. These are "stated" preferences because customers are asked to make choices amongst contingent or hypothetical options regarding new products or programs.[4] To

[4] "Stated" preference models are an outgrowth of the "conjoint" methods developed in the 1970's. A good summary of the methods and applications of conjoint analysis is given by Louviere (1988). These and more recent advances in "stated" preference models have been used extensively in marketing and transportation research, and more recently to examine preferences and values for public or environmental goods not traded in organized markets. See for example, McFadden (2001), Louviere (1988), and Hanley, *et al*. (1998) for discussions of the evolution of these methods. Goett, *et al*. (2000) in an unpublished paper also try to value service attributes from retail energy suppliers. Other applications include studies of how customers value electric service features by Long, *et al*., (1998), and Wood, *et al*., (2000).

place relative values on program features that differ from those available in the summer of 2002, a second discrete choice model was estimated using this "conjoint" survey information. These results provide a measure of the relative contribution of features to the value of participation, and thereby provide a means by which to assess programs different from the current ones . In addition to assigning values to alternative program features, the results of this second model can be used to forecast the odds of program participation due to changes in program design, a capability that has proved useful in evaluating proposed program redesign.

Each of the models is discussed separately below. The theoretical underpinnings of each are presented along with a discussion of the estimation procedures. A summary of the data used in each analysis is provided along with the estimated results, their interpretation, and their implications for policy. Where appropriate, we contrast these results with those of the 2001 evaluation (Neenan Associates, 2002).

Statistical Analysis of Customers' "Revealed Preferences"

As stated above, a major objective of this analysis is to gain a comprehensive understanding of those factors contributing to the supply of load reduction resources available to the New York State electricity market. This supply of resources is the sum of what is offered by individual firms. An important part of this determination is related to customers' decisions to participate in these programs. These decisions are clearly affected by the particular PRL program features, the types of customers throughout the State, market conditions, and any policy instruments in place to promote customer participation. In what follows, we examine specifically firms' decisions to participate in both the emergency programs (EDRP and ICAP/SCR) and the day-ahead program (DADRP). In this way, we are able to extend last year's analysis, which was limited to decisions whether or not to participate in EDRP.

Modeling the Decision to Participate in Current PRL Programs

Before specifying the empirical model of the decision to participate in the NYISO's PRL programs, we must outline a conceptual model and discuss some issues in estimation. We can appeal to a general set of discrete choice models that are most often cast in the form of an index function or random utility model (Greene, 1990). From a statistical standpoint, the discrete choice model is assumed to manifest some theoretically consistent underlying behavior. In this analysis, we are concerned with unordered choices from a set of three or more options, for example, the

choice of which shopping centers to do holiday shopping, the choice of modes of travel (e.g. car, train, bus, plane) to visit family over the holidays, or, as in our case, whether to participate in an emergency PRL program, participate in both an emergency and a day-ahead PRL program or not to participate in a program at all.

According to the underlying theory, the choice is based on the individual's or firm's marginal benefit—marginal cost calculation. If the net benefits of making a particular participation decision, net consumer utility or a firm's net income or utility of net income, are positive, then it is assumed that the decision is to participate in that particular program or combination of programs; otherwise, participation is eschewed.

The unordered multiple choice modeling problem is a challenging one because, regardless of the consumer's or firm's decision, we can never actually observe the marginal benefit, only the action consistent with that benefit. In economic terms, the marginal benefit is embodied in the notion of a consumer's or firm's utility, which is difficult, if not impossible to quantifiable in any meaningful way. Therefore, it is necessary to treat the difference between the marginal benefit and the marginal cost of the decision as an unobserved variable, the ith individual's utility of choice j. Thus, for the ith individual faced with J choices, suppose that the utility of choice j is given by:

(1) $U_{ij} = \beta' Z_{ij} + \varepsilon_{ij}$,

Z_{ij} = is a vector of program features and/or customer characteristics where the program feature level include those of the programs currently available and additional values representing alternative program designs;

β' = vector of parameters to be estimated; and

ε_{ij} = an error term.

Following Green's (1990, pp. 695-700) discussion, we will assume that if the individual (or firm) makes choice j, then the utility of that choice U_{ij} is the maximum among the utilities for all other possible choices. Consequently, the statistical model representing this situation can be represented by the probability of that choice, which is:

(2) Prob $[U_{ij} > U_{ik}]$ for all other $k \neq j$.

To make the model operational, we must choose a distribution for the disturbances ε_{ij}, and since the multivariate probit model involves evaluating multiple integrals of the normal

distribution, it is of limited use here. However, as McFadden (1973) has shown, if the J disturbances are independently and identically distributed (*iid*) with a Weibull distribution, then, if Y_i is the random variable indicating the choice made, we have:

(3) $\text{Prob}\,[Y_i = j] = e^{\beta' jZij} / \sum_j e^{\beta' Zij}$,

which is called a conditional logit model.[5] In (3), Prob $[Y_i = j]$ is the probability of choice j from the set of alternatives considered.

In this model, utility can be assumed to depend of Z_{ij}, which includes characteristics of the individuals or firms (i) and of the choices (j) as well. It can be useful to distinguish them as $Z_{ij} = [X_{ij}, W_i]$, where W_i are characteristics that are common to all decisions

Thus, the model becomes:

(4) $\text{Prob}\,[Y_i = j] = e^{\beta' jXij + \alpha' Wi} / \sum_j e^{\beta' jXij + \alpha' Wi}$

The terms that do not vary across alternatives (the W_i) now fall out of the probability calculation. One way to deal with this problem is to create dummy variables for the choices and multiply them by the common firm or individual characteristics, W. Since we are primarily interested in identifying the important firm characteristics that affect participation in PRL programs, we use this convention extensively in the empirical specification below.

The model for PRL program choice (no program [0], in one or both emergency programs [1], and in an emergency program plus the day-ahead program [2]) can be formulated for the choice set (j = 0, 1, 2,) as follows:

(5) $\text{Prob}\,[Y_i = j] = e^{\beta' jZij} / \sum_{j=0,\,1,\,2} e^{\beta' jZij}$

For these j + 1 choices, there is an indeterminacy in the model(Greene, 1990) that can be resolved by a convenient normalization on the no-choice option [0]:

(6) $\text{Prob}\,[Y_i = j] = e^{\beta' jZij} / \sum_{j=1,\,2} e^{\beta' jZij}$ for j = 1, 2

(7) $\text{Prob}\,[Y_i = 0] = 1 / \sum_{j=1,\,2} e^{\beta' jZij}$

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[5] This conditional logit model suffers from what is called the independence of irrelevant alternatives (IIA), in that the ratio of the probabilities of any two alternatives is always independent of the other choice probabilities. Although this is not an appealing restriction to place on choice behavior, it is not a particular problem in this application because all firms are given the same 20 choice sets from which the choices are to be made (Allison, 1999). The IIA assumption, as it is called, can only be tested if some sample members have different choice sets (Allison, 1999, pp. 167-68), so in this case, there is no way to test for any bias.

It can further be shown that the estimated coefficients can be used to calculate the log of the odds ratios between j and the no-choice option.[6] These are given by:

(8) $\ln [P_{ij} / P_{i0}] = \beta'_j Z_i$,

where P_{ij} is the probability of choice I relative to choice J. We can normalize on any other probability by recognizing that:

(9) $\ln [P_{ij} / P_{ik}] = Z_i (\beta'_j - \beta'_k)$.

Model Estimation

Since this multinominal logit model has a dichotomous dependent variable, the choice model takes on a value of 0 or 1 or 2, it is only possible to estimate the coefficients of the model using weighted least squares (if there are grouped data) or maximum likelihood (ML) procedures (Allison, 1999 and Greene, 1990). Since we have do not have grouped data, we use the ML methods based on the Newton-Raphson algorithm. The ML method involves two steps: 1) construct the likelihood function, which is the expression for the probability of the data as a function of the model's unknown parameters, and 2) estimate parameter values, typically through an iterative numerical method, that maximize the value of the likelihood function. The CATMOD procedure in SAS is an effective way to do this estimation.[7]

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[6] Allison (1999) argues that it is helpful to place it into context with the notion of odds and odds ratios as a means to quantify the chances of an event occurring, rather than in terms of the event's probability. The probability of an event occurring is bounded between zero and one. In contrast, the notion of odds is one used in many games of chance—the odds of an event is the ratio of the expected number of times an event will occur to the number of times it is expected not to occur. The relationship between odds (O) and probabilities (p) is: O = p / (1 – p) = [probability of event] / [1 – probability of event], and p = O / [1 + O].

Thus, if the odds are less than 1, the probability of the event is less than 0.5. Because of this simple relationship between odds and probability, one can always derive one from the other, and thus the probability model above can be couched in either way. The major advantage for using the odds (or the odds ratio) in comparing the likelihood of two events is that neither the odds of one event nor the odds ratio between two events occurring is bounded between zero and one. Thus, by transforming the probability to an odds and then taking its logarithm, we can remove both the upper and lower bound on the variable of interest.

Although Allison's argument is couched in terms of a binary choice model, the same principles apply to a multiple-choice model where the odds ratios apply to the ratios of the probabilities of any two of the choices. In this case, it is not so easy to derive the individual probabilities from the odds themselves.

[7] Maximum Likelihood estimators are used widely because of their good large sample properties (Allison, 1999). Most econometric texts (e.g. Greene, 1990, and Maddala, 1983) discuss these properties, and under quite general conditions, ML estimators are consistent, asymptotically efficient, and asymptotically normal.

The Empirical Specification of the Decision Model of PRL Program Participation

The data used to specify this model empirically comes from Part I of the Customer Acceptance Survey administered to New York electricity customers by Neenan Associates as part of the 2002 evaluation of NYISO's price responsive load programs. There were a total of 144 usable responses to the survey, which asked customers to provide, among other things, information about their participation in PRL programs, how they learned about the programs, their understanding of the programs, and characteristics about their business operations that might be related to their decision to participate in either ICAP/SCR, EDRP, or DADRP.[8] A complete description of the survey methodology and a summary of the descriptive data for all respondents are provided in Chapters 2 and 3.

Of the 144 respondents, 58 (40.3%) are participants only in EDRP; another 16 (11.1%) participate in both ICAP/SCR and EDRP (Table 4-10). A total of 11 respondents are enrolled in DADRP; 4 of them are also in EDRP, while the remaining 7 are also in both ICAP/SCR and EDRP. The remaining 59 (41%) of survey respondents are in none of the three PRL programs (Table 4-10). They represent the population of customers that were contacted about PRL participation in 2002, but chose not to participate in any program.

As stated above, we define three categories of respondents for the purposes of our analysis. We designated non-participants as one group (59 respondents or 41% of the total). A second group includes those customers enrolled in at least one of the two emergency programs (EDRP or ICAP/SCR), or both (74 respondents or 51% of the total). The final group includes those respondents in DADRP (11 respondents or about 8% of the total); these individuals are treated separately to identify specific, distinguishing characteristics that affect participation in DADRP. However, it must be acknowledged that all respondents in DADRP are also in EDRP or EDRP and ICAP/SCR. Thus, our model in a sense is trying to identify factors that explain participation in only emergency programs vs. joint participation in day-ahead and emergency programs.

In specifying the empirical model, we classified factors affecting participation into several general categories: a) those that represent the customer's load profile, b) those that characterize the nature of the firm's production processes, c) those that reflect past experience

[8] The survey is included as an appendix of the report.

with load management programs, and d) those that measure the usefulness of the information they received about the program prior to their decision to join. This categorization resulted from preliminary analysis of the data. There are a number of questions in the survey that are related to each of these categories, and a number of models were estimated using a subset of variables to comprise each of these categories. Some of the several variables within each category were understandably correlated with one another. In these cases, it was impossible to statistically isolate the separate contributions of each of these variables on the program participation decision. For this reason, the final model specification included only one or two variables in each of the five categories.

All the variables in the model relate to firm characteristics, and are zero-one categorical variables, as follows:

- Access = 1, if the firm answered "yes" to one or more of the survey questions asking if it had ready access to real-time load information, CBL level, etc., = 0, otherwise.
- Attend_show =1, if the firm attended one of the 2002 PRL program informational meetings sponsored by the PSC, NYSERDA, etc., = 0, otherwise.
- Gen = 1, if the firm had on-site generation to meet PRL load response commitments, = 0, otherwise.
- Lse_pgms = 1, if the firm has had previous experience with an LSE's load management program.
- Manufact = 1, if the firm is a manufacturing firm, = 0, otherwise.
- Nyserda =1, if the firm is participating in a NYSERDA PON, = 0, otherwise.
- Peak_12_4 = 1 if the firm has its peak electricity demand between noon and 4:00 pm, = 0, otherwise.

<u>The Empirical Results</u>

The results of the estimated multinominal logit model are in Table 4-11. The overall performance of this model is very good, as seen in the left-hand section of Table 4-11 labeled

"Global Analysis of Variance",[9] where all but two of the variables, gen and peak_12_4, are globally significant at least at the 10% level. The very high p-value (0.9885) for the likelihood ratio test also suggests a very good fit overall.

The estimated coefficients of the model are reported in the right-hand section of Table 4-11. Each variable has two coefficients associated with it. The first reflects the effect of that variable on the log-odds ratio of participating in DADRP & Emergency Programs vs. No Program, and the second reflects the effect of that variable on the log-odds ratio of participating in Only an Emergency vs. No Program. The effect on the log-odds ratio of participating in the third program combination (DADRP & Emergency Programs vs. Only an Emergency Program) is then calculated according to equation (9) above. From Table 4-11 we can see that 11 out of the 16 coefficients are significant at least at the 0.05 level. Many variables have a significant effect on the log-odds ratio comparing the probabilities of one program combination, but not another, for example gen and attend_show.

To facilitate interpreting the results, we convert the log-odds ratios to odds ratios. We do this in Table 4-12, and some of the results are striking. If the odds ratio is greater than unity, the probability of being in the first program for the comparison listed in a particular column of Table 4-12 is greater than the probability of being in the second program choice listed in the particular column of the table.

There are several important highlights from Table 4-12 that should be underscored. They include:

- If a firm has ready access to real-time load information, etc., it is nearly 12 times (11.87) more likely to be in DADRP and an emergency program than in no program at all (Table 4-12, column a), and 6.05 times more likely to be in both DADRP and at least one emergency program than in just one or more emergency program (Table 4-12, column e).
- Based on the model results, it is clear that the informational meetings helped firms make appropriate decisions about participating in the NYISO PRL programs. For example, if

[9] In the section of Table 4-2 labeled Global Analysis of Variance, the chi-square statistics are actually Wald statistics, except for the last line (Allison, 1999). Each Wald statistic tests the null hypothesis that the explanatory variable has no effect on the outcome (participation) variable. For these tests, a low p-value suggests that the variable has a significant effect on the outcome variable. The likelihood ratio test on the last line of this section of output in Table 4-2 is equivalent to the deviance statistic and is equal to twice the positive difference between the log-likelihood for the fitted model and the saturated model.

firms attended an informational meeting in 2002, they are *less* likely to be in an emergency program than in no program (odds ratio of 0.16 from column c, Table 4-12). However, if they are EDRP participants, they are more than three times more likely to be in both DADRP and an emergency program than just in an emergency program (odds ratio of 3.32 from column e, Table 4-12). Together, these imply that attending a briefing had a stronger influence on customers inclined to participate in an emergency program that to participate in DADRP.

- If a firm has on-site generation to meet PRL load response obligations in an emergency program, it was over three times more likely to be in EDRP and/or ICAP/SCR than in no program at all (odds ratio of 3.07 from column c, Table 4-12).
- Since a firm cannot use on-site generation for DADRP, we gain some added confidence in the model results because the model predicts that firms with on-site generation are *much less* likely to be in both DADRP and an emergency program than in either "just an emergency program" (odds ratio of 0.30 from column e, Table 4-12).[10]
- Firms with prior experience in an LSE's load management program are 1.7 times more likely to participate in an emergency program than in no program. (column c, Table 4-12).
- However, firms with prior experience in load management programs are over 9 times more likely to be in at least one of the two emergency programs and DADRP (odds ratio of 9.06, column a, Table 4-12), and they are 5.32 (column e, Table 4-12) more likely to be in at least one emergency program and DADRP than in just an emergency program.
- Manufacturing firms are 5.58 (column c, Table 4-12) times more likely to be in an emergency program than in no program, and if they are PRL participants, they are 14.76 (column e, Table 4-12) times more likely to be in both emergency programs and DADRP than in just an emergency program.
- The model predicts that manufacturing firms are over 80 times more likely to be in at least one emergency program and DADRP than in no program (odds ratio of 82.31, column a, Table 4-12). While this is an important result, this very high odds ratio probably has as more to do with the particular nature of sample respondents than the

[10] It is also not surprising that this coefficient is statistically insignificant.

nature of all manufacturing firms. That is, the types of manufacturing firms finding little possible value in these PRL programs may have not been sufficiently interested in learning more about the programs, as a result decided not to attend a briefing, and therefore were not included in the informed non-participant sample frame. They may also have just not completed the survey questionnaire.

- As one would expect, participants in a NYSERDA PON were much more likely (odds ratio of 66.36, column c, Table 4-12) to participate in an emergency program than no program at all, and they were also more likely (odds ratio of 33.19, column a, Table 4-12) to participate in both DADRP and an emergency program. Accordingly, the model also predicts that firms in a NYSERDA PON are *less* likely to be in both DADRP and an emergency program than in just an emergency program (odds ratio of 0.50, column e, Table 4-12).
- Firms with peak loads during the afternoon hours (noon to 4:00 pm.) are 2.36 (column c, Table 4-12) times more likely to be in an emergency program than in no program, and 3.04 (column a, Table 4-12) times more likely to be in an emergency program and DADRP.

Modeling Customers' "Stated" Preferences for PRL Program Features

The modeling of the "stated" preferences of customers for PRL program features can also be accomplished within a random utility formulation. This analysis was facilitated in Part II of the Customer Acceptance Survey by having respondents make several choices from among four PRL programs, with each choice indicating different values for five program features, and a "no program" alternative.[11] Survey respondents were asked to indicate their preference on each of twenty such choice sets.

The Choice Model

As above, we model this choice situation as though the ith customer is faced with J choices, and the utility of the choice j is given by:

[11] A copy of the survey instrument is provided in the appendix to Chapter 2. The features used in the choice sets represent the major PRL program characteristics. The range in values used in creating the choice sets reflect those ascertained by the research team as feasible, given NYISO's operating procedures and market rules.

(10) $U_{ij} = \beta' Z_{ij} + \varepsilon_{ij}$.

where

U_{ij} = the utility of customer i making choice j;

Z_{ij} = is a vector of program features and/or customer characteristics where the program feature level include those of the programs currently available and additional values representing alternative program designs;

β' = vector of parameters to be estimated; and

ε_{ij} = an error term.

If the customer chooses program j, then it is assumed that U_{ij} is the maximum of the utilities for all the J alternatives. The statistical model is driven by the probability that choice j is made:

(11) Prob $[U_{ij} > U_{ik}]$ for all $k \neq j$.

This indicates the probability that the utility of choice j for individual i is greater than the utility of any other choice k.

To make this model operational, we again must make an assumption about the distribution of disturbances, ε_{ij}. Following McFadden (1973) and Greene (1990), we let Y_i be a random variable for the choice made. It can be shown that if (and only if) the disturbances are independent and identically distributed according to a Weibull distribution, then

(12) $F(\varepsilon_{ij}) = \exp(-e^{-\varepsilon ij})$,

and we can express the probability of choice j by individual i (Prob $[Y_i = j]$) as:

(13) Prob $[Y_i = j] = \exp[\beta' Z_{ij}] / \{\sum_j [\exp \beta' Z_{ij}]\}$,

which is called the conditional logit model.

In this conditional logit model, utility (as expressed through the choice made) is assumed to depend on both characteristics of the choices considered and the firm's characteristics. It is helpful, therefore, to distinguish between the two sets of factors. $Z_{ij} = [X_j + W_i]$, where the former, X_j, are the variables that characterize program features, and the latter, W_i, are firm characteristics. The model now can be written more explicitly as.

(14) Prob $[Y_i = j] = \exp[\beta' X_j + \alpha' W_i] / \{\sum_j [\exp(\beta' X_j + \alpha' W_i)]\}$

In this formulation, the alternative choices that are explicit to the firm making the decision fall out, because while a firm makes 20 decisions as part of the survey exercise, and those choices reflect differences in program features, its firm characteristics do not vary from choice to choice, and they do not vary even across the several data observations that must be constructed for each choice set. This will lead to singularities in the data matrix if estimation is attempted in this form. Therefore, if these factors are to be in the model, the model must be modified. An effective modification is to create a set of dummy variables for the choices and multiply each by the common W_i set of firm characteristics (Greene, 1990).[12]

This modeling strategy was used extensively in the revealed preference model above. However, there are two reasons why it is used only to a very limited extent in this "stated" choice application. First, in contrast to the revealed choice analysis which focuses primarily on decisions to participate in existing programs, the primary focus of this "stated" choice analysis is to understand how program features affect participation. Second, due to the greater complexity of the choices available and the smaller number of respondents completing part II of the survey, the only firm characteristic modeled was whether or not the firm is a current EDRP participant. This is a similar specification to last year's analysis (Neenan Associates, 2002), thus, facilitating comparisons with last year's results.

The resulting model, as in the case of the model above, is estimated by the method of maximum likelihood, in this case estimating the model in SAS using PROC PHREG.

<u>The Empirical Specification</u>

The key to understanding the empirical specification of the conditional logit model is to discuss explicitly what is in ($\beta' X_j + \alpha' W_i$). In contrast to other applications, each of the programs in the choice sets are characterized exclusively by five separate program features, each

[12] Because all firms are given the same 20 choice sets from which the choices are to be made this application conditional logit model also suffers from what is called the independence of irrelevant alternatives (IIA), in that the ratio of the probabilities of any two alternatives is always independent of the remaining probabilities (Allison, 1999). The IIA assumption, as it is called, can only be tested if some sample members have different choice sets Allison, 1999, pp. 167-68), so in this case too, there is no way to test for any bias.

of which can assume one of four separate values. These features include (the units are in (), and the specific values used to construct the individual choices are in { }):[13]

1. Payment level ($/kWh) { 0.10, 0.25, **0.50**, 0.75 }, what participants are paid for curtailments;
2. Penalty (multiples of payment) { **0**, 0.1, 0.25, 0.50 }, the amount participants pay if they fail to comply when called on to do so;
3. Start Time { 11am, 12noon, **1pm**, 2pm }, when the curtailment begins;
4. Notice (prior to curtailment) { 30 min., **2 hrs**, 4 hrs, noon day-ahead }, the length of time prior to the event that customers are notified that they will have to curtail; and
5. Event Duration { 1hr, 2hrs, **4hrs**, 30 min }, how long the curtailment event lasts.

Each of these values for the program features was assigned a dummy variable [0,1] for inclusion in the model. Since it is necessary to eliminate one of the dummy variables from each of the features so that the data matrix is non-singular, we eliminated the variable associated with the values in bold above. In this way, the empirical results are normalized on the base program, which consists of a payment of $500/MWh, no penalty, a 1:00 pm start time, a 2-hour notice and 4-hour event duration. For convenience of interpretation, the base program was chosen to resemble the current EDRP configuration.

For the two reasons outlined above, the only firm characteristic included in the empirical estimation is a dummy variable indicating if the firm is a participant in EDRP. To capture this firm effect, the other variables for program features were multiplied by this one firm-level dummy variable to create the necessary interaction variables.[14]

The specification of the linear function ($\beta' X_j + \alpha' W_i$) can now be given as:

$$(15) \quad \{ \textstyle\sum_{k=1,2,4} \beta_{1k} PAY_k + \sum_{k=2,3,4} \beta_{2k} PEN_k + \sum_{k=1,2,4} \beta_{3k} ST_k + \sum_{k=1,3,4} \beta_{4k} NT_k + \sum_{k=1,2,4} \beta_{5k} DUR_k \} + \{ \textstyle\sum_{k=1,2,4} \alpha_{1k} PAY_k (EDRP\text{-}DUM)$$

[13] The values of these program payments are somewhat different from those used in the 2001 evaluation. In 2001, the alternative payment levels were set at { **0**, 1, 1.5, 2 } (see Neenan Associates, 2002). Also the 30-minute notice in 2002 replaced the 15-minute notice in the 2001 evaluation, and the 30-minute duration in 2002 replaced the 8-hour duration of a year ago.

[14] By specifying the model in this way, we also obtain a natural test of the hypothesis that the effects of the various characteristics on program choice are not different for EDRP participants and non-participants.

$+ \sum_{k=2,3,4} \alpha_{2k}\ PEN_k\ (EDRP\text{-}DUM) + \sum_{k=1,2,4} \alpha_{3k}\ ST_k\ (EDRP\text{-}DUM)$

$+ \sum_{k=1,3,4} \alpha_{4k}\ NT_k\ (EDRP\text{-}DUM) + \sum_{k=1,2,4} \alpha_{5k}\ DUR_k\ (EDRP\text{-}DUM)\ \}$

$+ \gamma\,(NO\text{-}CHOICE) + \gamma\,(NO\text{-}CHOICE)\ (EDRP\text{-}DUM).$

The last two terms in the specification assign a value to the "no-program" choice option that was included in each of the 20 choice sets given to customers.

<u>The Values for PRL Program Features</u>

To begin the discussion and as seen in Table 4-13, 69 survey respondents answered the conjoint survey (Part II of the Customer Acceptance Survey). Of that number, 34 are participants in only EDRP; 9 participate in both ICAP/SCR and EDRP. There are also 8 respondents in DADRP; and of these, 2 are also in EDRP and the remaining 6 are also in both ICAP/SCR and EDRP (Table 4-13). Finally, 18 of the respondents are non-participants.

In responding to the 20 choice sets, the non-participants preferred no program over participation an average of 7.5 times out of the 20 choice sets they evaluated. The range of responses was from 0 "no-program" choices to 20 "no-program" choices (Table 4-13). In contrast, the participants only in EDRP selected the "no-program" choice an average of only 6.5 times, and the maximum number of "no-program" choices was 20. The participants in both ICAP/SCR and EDRP selected the "no-program" choice an average of 11.7 times, and the maximum number of "no-program" choices was 17.

Although differences in these summary responses between participants and non-participants are not as dramatic as they were last year,[15] we still estimated the model for the two groups to see if they value the program features differently.[16] As is seen below, the similarity in responses across groups leads to smaller differences in the values for program features between the subgroups of respondents than was seen last year (Neenan Associates, 2002).

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[15] It is difficult to know why this is so, but part of the explanation is perhaps because this was the first year that some of the respondents participated in any PRL program. The first-year participants may find slightly less value in the programs (even though they are enrolled) than firms that have been enrolled since 2001. Thus, they may value particular program characteristics somewhere in between non-participants and participants in the program for a second year.

[16] There were not sufficient DADRP participants to treat them as a separate group in the analysis.

2002 NYISO PRL Evaluation

The results of the estimated conditional logit model are in Table 4-14. Again the overall performance of this model is very good. The joint tests of all the coefficients being equal to zero are rejected soundly, as shown in the bottom right box of Table 4-14. Regarding the specific parameter estimates, the coefficients on payment and penalty for non-participants are statistically significant as well. However, many of the interaction terms for the program participants are not statistically significant, except for some of the interaction variables for notice and duration.

Thus, despite the good overall performance of the model, there is less evidence than in the 2001 evaluation (Neenan Associates, 2002) that participants and non-participants value these program features differently. However, even though many coefficients are not significant, they are left in the model. This was done for two reasons. First, by doing so, we do obtain a value for the individual feature value, which is in most of those cases very small. Second, and perhaps equally important, by leaving them in the model, we do not run the risk of introducing bias into the other coefficient estimates if these variables happen to be correlated with the ones that might be dropped.

In interpreting these results, we can think of the "base" program (which can be viewed as EDRP) as yielding an average utility of zero. This normalization is convenient because in estimating a model in which dummy variables are used to indicate different levels of program features, it is necessary to eliminate one set of program features. Further, since utility measures are always relative, the results and relative comparisons for programs differently configured are independent of this reference point, and it made sense to make this "base" case mimic EDRP. Thus, if the coefficient on the particular value of a feature is positive, then, *ceteris paribus*, it is preferred to the "base" program feature since it is above the reference level of zero. If the coefficient is negative, then the reverse is true. In Fig. 4-27 through 4-36, the relative feature values are graphed for the two sub-groups of respondents. For purposes of comparison, the figures also contain the values from the 2001 evaluation (Neenan Associates, 2002). Again, in all cases, these program feature values are relative to the "base" features: a $500/MW payment, a zero penalty, a 1:00 pm start time, a 2-hour notice, and a 4-hour event duration.

In Fig. 4-27 through 4-36, several striking relationships are revealed by comparing the value of features across the two sub-groups and across years:[17]

[17] Some care must be taken when interpreting the results because some of program feature values are different between the two survey years.

- For 2002, the relative utility of the smallest payment rate is just slightly lower for PRL participants than for the non-participants. The utilities for the highest payment rate are about the same for both groups (Fig. 4-27 and 4-28). Clearly, the level of payment is very important for both groups in deciding whether or not to participate in the PRL programs, but differences between them are small.
- In sharp contrast, the 2001 results suggested that the relative utility of the smallest payment rate was substantially lower for EDRP participants, but higher for the largest payment rate (Fig. 4-27 and 4-28).
- As was the case in 2001, the dis-utility of the penalty is more pronounced for 2002 PRL participants than for non-participants (Fig. 4-29 and 4-30).
- Compared with last year, the dis-utilities of the penalty fall less rapidly as the penalty rises for both groups of 2002 respondents (Fig. 4-29 and 4-30). This result is explained in part by the fact that the 2002 survey reflected smaller penalty rates. These rates were changed for the 2002 survey because from last year's survey some respondents appeared to have some difficulty in understanding the penalty. However, given this year's results, it appears that this was not the case.
- For 2002 respondents, non-participants place a higher value on start times either earlier or later than 1:00 pm (Fig. 4-31 and 4-32). Participants, on the other hand, seem to prefer later start times, suggesting that participants see a reduction in outage costs of load curtailment if the events begin later in the afternoon.
- There is a general preference for a longer notice period by 2002 respondents currently participating in a PRL program (Fig. 4-33 and 4-34). They clearly placed negative values on notice periods of less than an hour. There was substantial consistency in this regard relative to last year, but this year the 30-minute notice carried a smaller negative value this year than the 15-minute notice did in last year's survey. In contrast to last year, however, PRL participants responding to this year's survey placed a high value on the day-ahead notice. It may be EDRP participants have come to value greater notice since under this year's provisions, EDRP and ICAP/SCR were called coincidently, and ICAP/SCR provides a 24-hour notice of the intent to curtail, followed by a two-hour advance announcement of the actual event.

- In contrast to last year, where non-participants placed an increasing value on length of notice, there was no significant difference between the value of the base notice and any other notice time for this year's non-participant respondents (Fig. 4-33 and 4-34).
- As with 2001, there is a general preference for longer durations by PRL participants. (Fig. 4-35 and 4-36). Both sub-groups assigned the highest levels of dis-utility to the 30-minute duration.
- In both years, non-participants seemed to prefer either very short or very long durations; they assigned the highest dis-utilities to the 2-hour duration in both years (Fig. 4-35 and 4-36).

Preferences for Some Re-Designed Programs

We can now use the results from the conditional logit model to examine customers' preferences for programs with different features. As seen in Table 4-15, the total utility of the "base" (EDRP) program for current PRL program participants (normalized to "zero") is higher than the "no program" option, *ceteris paribus.* The "no program" option reduces utility by 0.57 (the row for "total utility" and column for "no program" in Table 4-15), which is interpreted as follows: if the decision were to be made between the "no program" and the "base" program, there are odds of 1.78 to 1 that these customers would sign up (the customer utility value in Table 4-15 for the row "odds of program vs. no program" and "base program" column).

As the value for utility and the odds ratio for Program Options P1-P5 in Table 4-15 indicate, customers would prefer a program with a higher payment (Program Option P1) but eschew a program with shorter notice and duration (Program Option P2). It is noteworthy that in spite of the dis-utility associated with a modest penalty, it can be compensated for by a longer notice and higher payment rate, as illustrated by Program Option P5. For this option, the odds of participating in this program relative to no program are 1.33 to one. This particular option was constructed to mirror the current DADRP (day-ahead notice, penalty = 0.1). In contrast to last years results where achieving an odds of participation ratio of 1:1 required only a $250/MW strike price, this year's respondents would require a $750/MW strike price. One way to interpret this result is that current PRL participants are unlikely to find DADRP attractive unless they can be guaranteed to be scheduled a significant number of times at a strike price of $750/MW). This is consistent with the strike prices respondents indicated they would require to bid in DADRP, which averaged $.87/kWh (see Chapter 4).

From Table 4-16, it is not surprising that the utility of the "no program" option (0.06) for non-PRL participants is higher than it is for the "base" program (0.0). They have already turned down an opportunity to participate in a PRL program, and it is extremely encouraging that the results of this "stated" preference model are consistent with the "revealed" preferences of these customers. If this were not the case, one might well question whether their responses to the choice sets could be used to predict future behavior.

For this sub-group of customers, it requires very high levels of beneficial feature to achieve a program design that is preferred to the "base", as well as to find programs preferred to the "no program" option. This also is not a surprising result. Since non-participants could not find enough value in EDRP to participate currently, they would need a higher payment or a later start time in order to generate even odds or better than even odds of participation (e.g. Options P1 and P3 in Table 4-16).

Table 4-10: Summary Data on Customer Acceptance Survey Part I

Item	Number of Customers	% of Total
Non-Participants	59	41.0
EDRP & SCR	16	11.1
DADRP & EDRP	4	2.8
DADRP, EDRP & SCR	7	4.9
EDRP Only	58	40.3
Total	144	

Table 4-11: Multinomial Model Results from Revealed Choice Analysis, 2002

	Global Analysis of Variance			Parameter Estimates				
Parameter	DF	Chi-Square	Pr > ChiSq	Function Number	Estimate	Standard Error	Chi-Square	Pr > ChiSq
Intercept	2	16.8	0.0002	1	-7.6939	1.9433	15.68	<.0001
				2	-1.048	0.5397	3.77	0.0521
manufact	2	17	0.0002	1	4.4105	1.2119	13.24	0.0003
				2	1.7184	0.5552	9.58	0.002
gen	2	3.95	0.1389	1	-0.098	1.3929	0	0.9439
				2	1.1202	0.6175	3.29	0.0696
peak_12_4	2	3.59	0.1659	1	1.1118	0.8692	1.64	0.2009
				2	0.8594	0.4745	3.28	0.0701
nyserda	2	15.21	0.0005	1	3.5022	1.3207	7.03	0.008
				2	4.1951	1.0915	14.77	0.0001
access	2	4.48	0.1064	1	2.4744	1.244	3.96	0.0467
				2	0.6735	0.5056	1.77	0.1828
lse_pgms	2	6.09	0.0476	1	2.2035	0.894	6.08	0.0137
				2	0.5324	0.526	1.02	0.3115
attend_show	2	14.23	0.0008	1	-0.6311	0.9218	0.47	0.4936
				2	-1.8319	0.5025	13.29	0.0003
Likelihood Ratio	**120**	**87.59**	**0.9885**					

Table 4-12: Summary of Revealed Choice Analysis, 2002

	DADRP & Emergency vs. No Program			Emergency Only vs. No Program			DADRP & Emergency vs. Emergency Only		
Parameter	Odds Ratio		Chi-Square Value	Odds Ratio		Chi-Square Value	Odds Ratio		Chi-Square Value
	(a)		(b)	(c)		(d)	(e)		(f)
Intercept	0.00	**	15.68	0.35	**	3.77	0.00	**	12.32
access	11.87		3.96	1.96		1.77	6.05		2.33
attend_show	0.53		0.47	0.16	**	13.29	3.32		2.04
gen	0.91		0.00	3.07	*	3.29	0.30		0.89
lse_pgms	9.06	**	6.08	1.70		1.02	5.32	**	4.30
manufact	82.31	**	13.24	5.58	**	9.58	14.76	**	5.56
nyserda	33.19	**	7.03	66.36	**	14.77	0.50		0.74
peak_12_4	3.04		1.64	2.36	*	3.28	1.29		0.10

Note: the odds ratios are the ratios of the probability of participating in the first program or set of programs vs. the second program or set of programs listed in the column headings.
Note: Recall that is the odds ratio is greater than unity, the probability of being in the first program listed a particular column of this table is greater than the probability of being in the second column listed.
Note: The * and ** indicate the coefficients are statistically significant at least at the 10% and 5% level, respectively.

Table 4-13: Summary Data on Customer Acceptance Survey Part II

Item	Number of Customers	Number of "No Program" Choices: Average	Standard Deviation	Minimum	Maximum
Non-Participants	18	7.5	8.0	0.0	20.0
EDRP & SCR	9	11.7	4.1	5.0	17.0
DADRP & EDRP	2	8.5	12.0	0.0	17.0
DADRP, EDRP & SCR	6	6.0	3.3	1.0	11.0
EDRP Only	34	6.5	6.0	0.0	20.0
Total	69				

Table 4-14: Conditional Logit Model Results for the "Stated" Choice PRL Program Characteristics

	For EDRP Non-Participants						Increment Added to Coefficients for EDRP Participants[#]					
Variable	Parameter Estimate	Standard Error	Chi-Square	PR > ChiSq	Odds Ratio	Variable	Parameter Estimate	Standard Error	Chi-Square	PR > ChiSq	Odds Ratio	Combined Parameter[#]
PAY_1	-0.94	0.26	12.97	0.00	0.39	EDRP-DUM X pay_1	-0.07	0.30	0.05	0.82	0.93	-1.01
PAY_2	-0.63	0.26	6.00	0.01	0.53	EDRP-DUM X pay_2	0.02	0.30	0.01	0.94	1.02	-0.61
PAY_3			BASE			EDRP-DUM X pay_3			BASE			
PAY_4	0.81	0.19	18.90	0.00	2.25	EDRP-DUM X pay_4	-0.23	0.22	1.10	0.29	0.80	0.58
PEN_1			BASE			EDRP-DUM X pen_1			BASE			
PEN_2	-1.04	0.20	28.09	0.00	0.36	EDRP-DUM X pen_2*	-0.42	0.24	3.13	0.08	0.66	-1.45
PEN_3	-1.47	0.22	44.71	0.00	0.23	EDRP-DUM X pen_3	0.06	0.25	0.06	0.81	1.06	-1.41
PEN_4	-1.67	0.24	48.54	0.00	0.19	EDRP-DUM X pen_4*	-0.34	0.29	1.42	0.23	0.71	-2.01
ST_1*	0.20	0.24	0.71	0.40	1.22	EDRP-DUM X st_1*	-0.13	0.28	0.23	0.63	0.87	0.07
ST_2*	0.29	0.23	1.56	0.21	1.34	EDRP-DUM X st_2*	-0.26	0.28	0.90	0.34	0.77	0.03
ST_3			BASE			EDRP-DUM X st_3			BASE			
ST_4	0.06	0.25	0.06	0.81	1.06	EDRP-DUM X st_4	0.21	0.29	0.52	0.47	1.23	0.26
NT_1	0.02	0.22	0.01	0.93	1.02	EDRP-DUM X nt_1	-0.29	0.27	1.11	0.29	0.75	-0.27
NT_2			BASE			EDRP-DUM X nt_2			BASE			
NT_3*	-0.05	0.23	0.05	0.82	0.95	EDRP-DUM X nt_3*	0.19	0.28	0.46	0.50	1.20	0.13
NT_4	0.03	0.22	0.02	0.89	1.03	EDRP-DUM X nt_4*	0.55	0.25	4.73	0.03	1.74	0.58
DUR_1*	-0.14	0.22	0.42	0.52	0.87	EDRP-DUM X dur_1	-0.72	0.25	8.12	0.00	0.49	-0.86
DUR_2	-0.45	0.25	3.34	0.07	0.64	EDRP-DUM X dur_2*	-0.36	0.28	1.62	0.20	0.70	-0.81
DUR_3			BASE			EDRP-DUM X dur_3			BASE			
DUR_4*	-0.03	0.22	0.01	0.90	0.97	EDRP-DUM X dur_4*	-1.01	0.26	14.94	0.00	0.37	-1.03
NO_CHOICE	0.06	0.27	0.04	0.84	1.06	EDRP-DUM X no_choice	-0.63	0.30	4.26	0.04	0.53	-0.57

Testing Global Null Hypothesis: BETA=0

Test	Chi Square	PR > ChiSq
Likelihood Ratio	1001	< .0001
Score	886	< .0001
Wald	654	< .0001

[#] To find the effects for EDRP participants relative to the non-participants, one added these coefficients to the ones for nonparticipants.

*Note: Although some coefficients for both groups were "not significant" they were retained for the graphic presentation, and they had little effect on the simulation exercises. This is a common practice if it is believed that eliminating a variable will bias the other coefficients.

Table 4-15: Program Preferences for Current PRL Program Participants

	Base Program		No Program		Program Option P1		Program Option P2		Program Option P3		Program Option P4		Program Option P5	
					Higher Payment		Shorter Notice/Duration		Non-Compliance Penalty		Lower Payment		Pseudo-DADRP	
Program Features	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility
Payment	$500/MWh	0.00	-		**$750/MWh**	0.58	$500/MWh	0.00	$500/MWh	0.00	**$250/MWh**	-0.61	**$750/MWh**	0.58
Penalty	None	0.00	-		None	0.00	None	0.00	**0.1**	-1.45	None	0.00	**0.1**	-1.45
Start Time	1300 Hrs	0.00	-		1300 Hrs	0.00	1300 Hrs	0.00	1300 Hrs	0.00	1300 Hrs	0.00	1300 Hrs	0.00
Notice	2 Hrs	0.00	-		2 Hrs	0.00	**30 Min**	-0.27	2 Hrs	0.00	2 Hrs	0.00	**Noon, DA**	0.58
Event Duration	4 Hrs	0.00	-		4 Hrs	0.00	**30 Min**	-1.03	4 Hrs	0.00	4 Hrs	0.00	4 Hrs	0.00
Total Utility		**0**		**-0.57**		**0.58**		**-1.30**		**-1.45**		**-0.61**		**-0.29**
Odds:Program vs Base				**0.56**		**1.79**		**0.27**		**0.23**		**0.55**		**0.75**
Odds:Program vs No Program		**1.78**				**3.18**		**0.48**		**0.42**		**0.97**		**1.33**

Table 4-16: Program Preferences for Current Non-PRL Program Participants

	Base Program		No Program		Program Option P1		Program Option P2		Program Option P3		Program Option P4	
					Later Start		Non-Compliance Penalty		Higher Payment		Pseudo-DADRP	
Program Features	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility	Feature Value	Customer Utility
Payment	$500/MWh	0.00	-		$500/MWh	0.00	$500/MWh	0.00	**$750/MWh**	0.81	$500/MWh	0.00
Penalty	None	0.00	-		None	0.00	**0.1**	-1.04	None	0.00	**0.1**	-1.04
Start Time	1300 Hrs	0.00	-		**1400 Hrs**	0.06	1300 Hrs	0.00	1300 Hrs	0.00	**1400 Hrs**	0.06
Notice	2 Hrs	0.00	-		2 Hrs	0.00	2 Hrs	0.00	2 Hrs	0.00	**Noon, DA**	0.03
Event Duration	4 Hrs	0.00	-		4 Hrs	0.00	4 Hrs	0.00	4 Hrs	0.00	4 Hrs	0.00
Total Utility		**0.00**		**0.06**		**0.06**		**-1.04**		**0.81**		**-0.95**
Odds of Program vs Base				**1.06**		**1.06**		**0.36**		**2.25**		**0.39**
Odds of Program vs No Program		**0.95**				**1.00**		**0.34**		**2.13**		**0.37**

Fig. 4-27: Relative Utility Levels of Payment Levels for PRL Participants

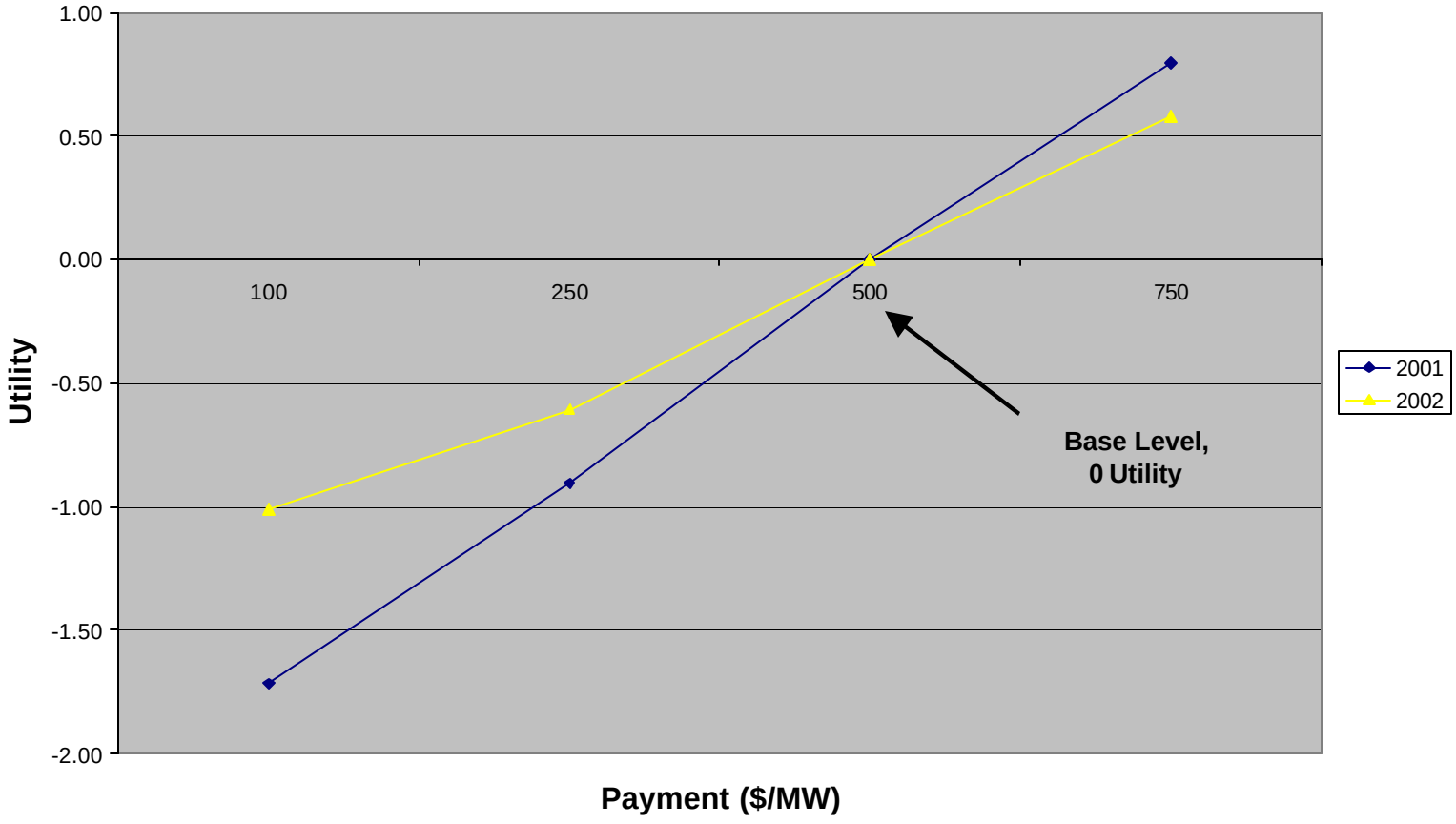


Fig. 4-28: Relative Utility Levels of Payment Levels for Non-PRL Participants

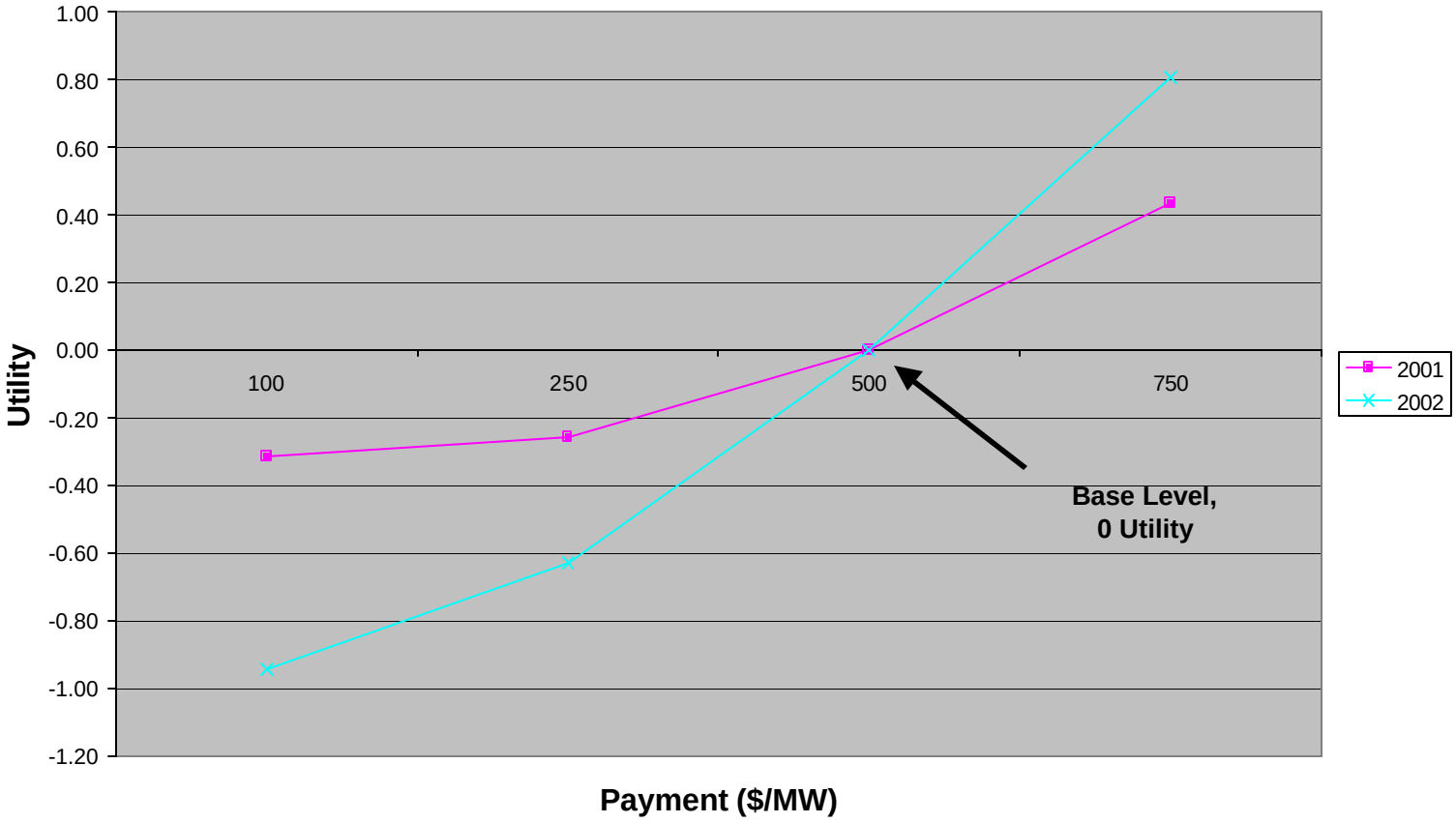


Fig. 4-29: Relative Utility Levels of Penalty Rates for PRL Participants

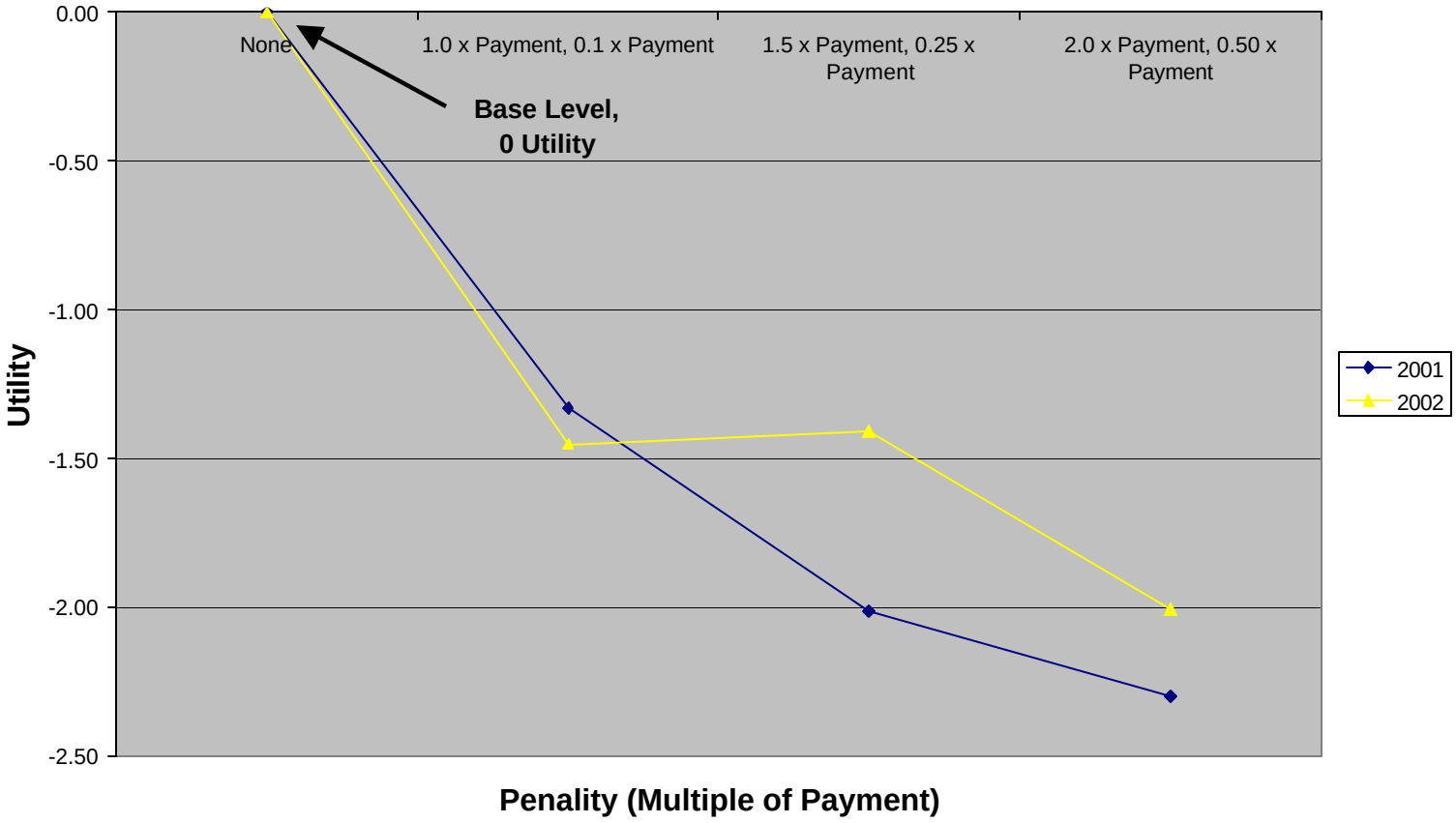


Fig. 4-30: Relative Utility Levels of Penalty Rates for PRL Non-Participants

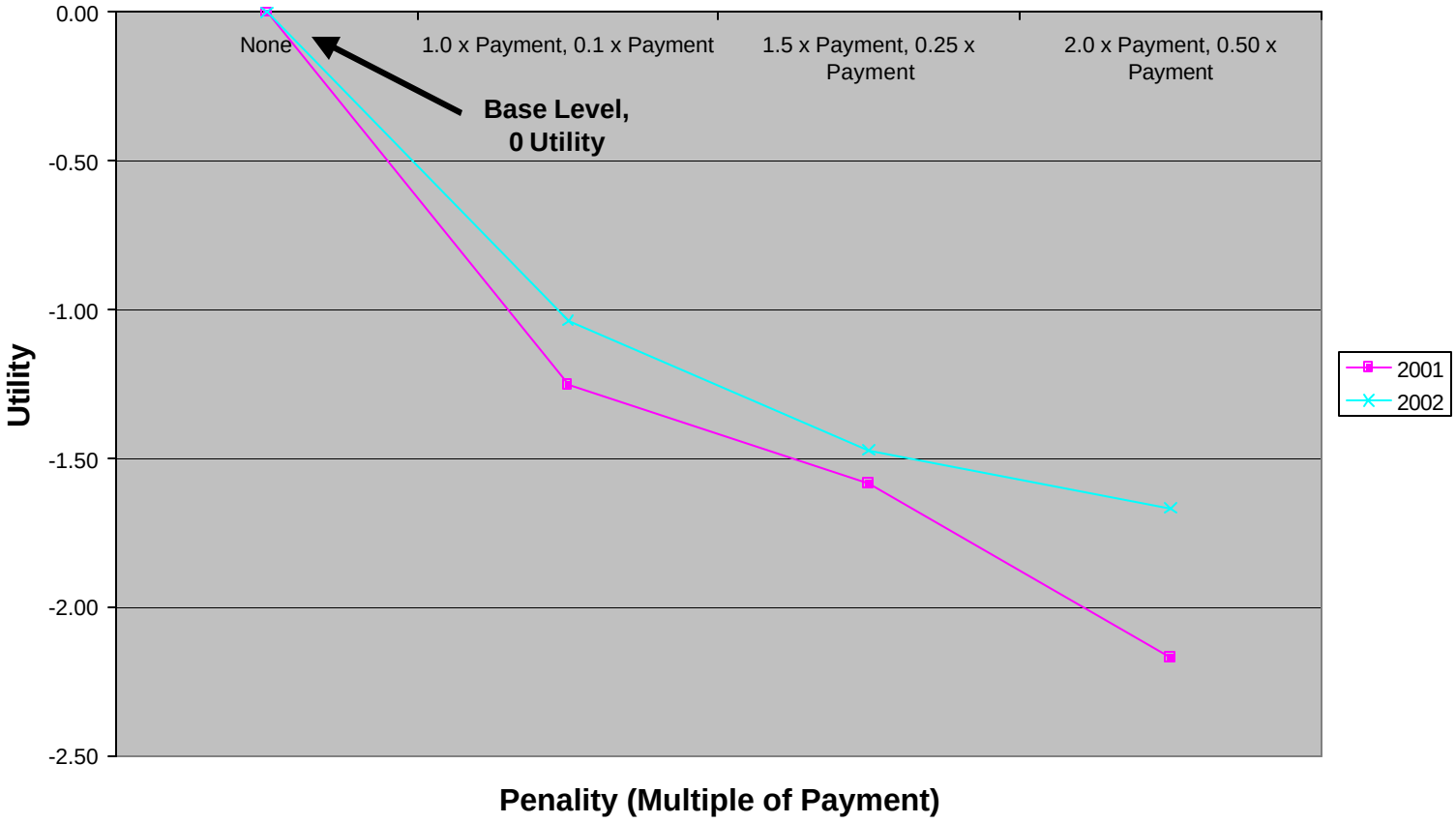


Fig. 4-31: Relative Utility Levels of Start Times for PRL Participants

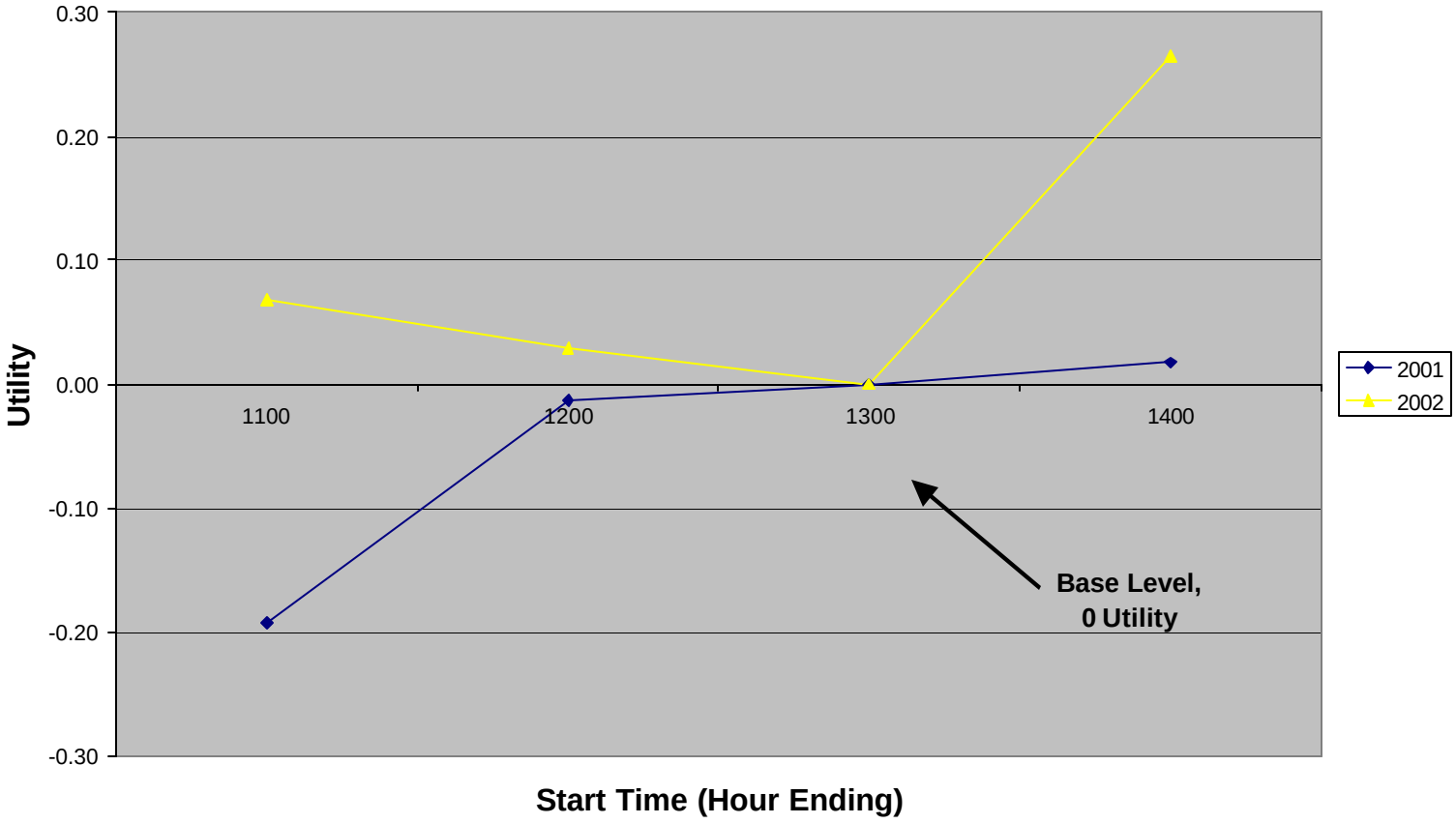


Fig. 4-32. Relative Utility Levels of Start Times for PRL Non-Participants

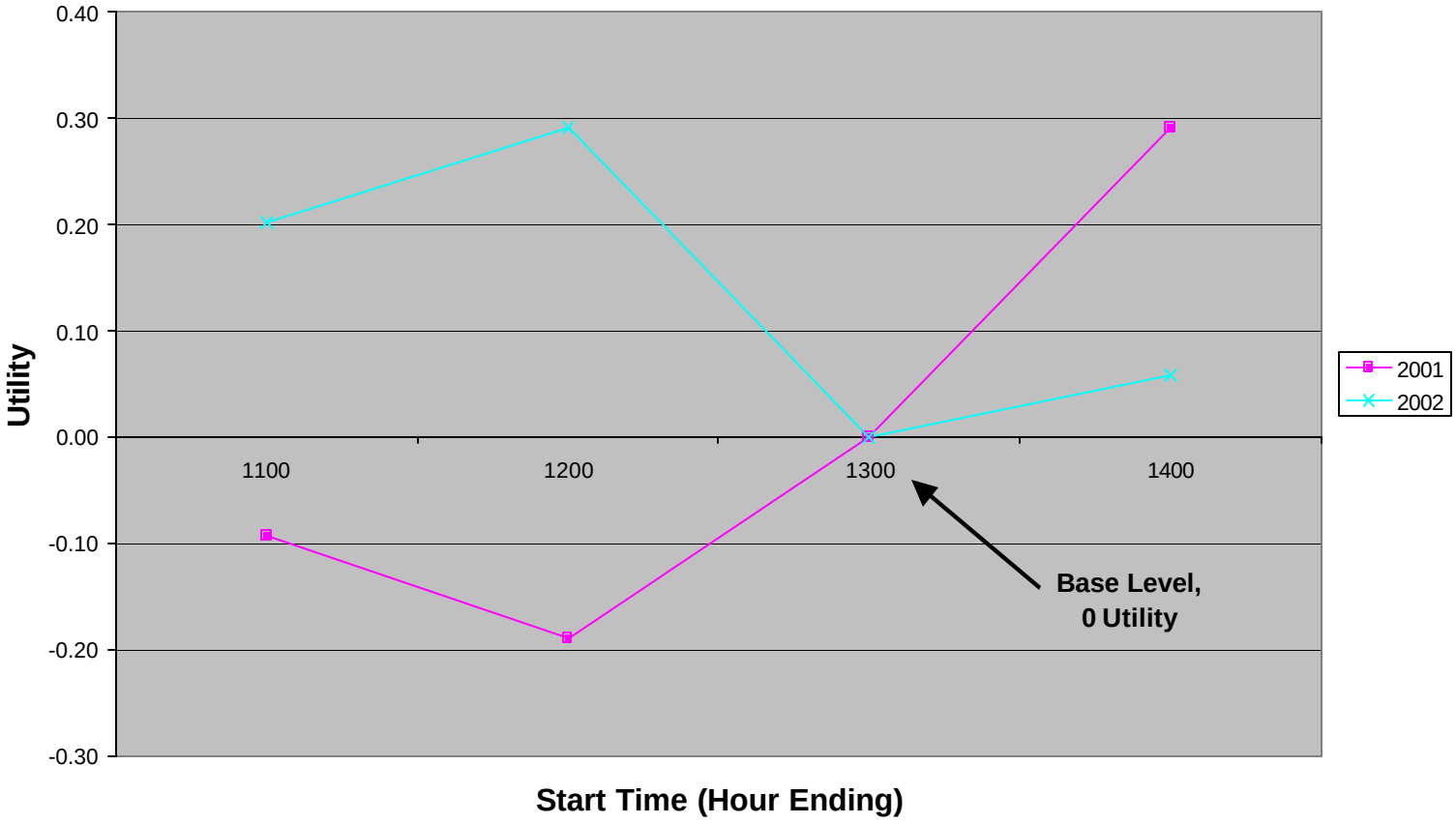


Fig. 4-33: Relative Utility Levels of Notice Periods for PRL Participants

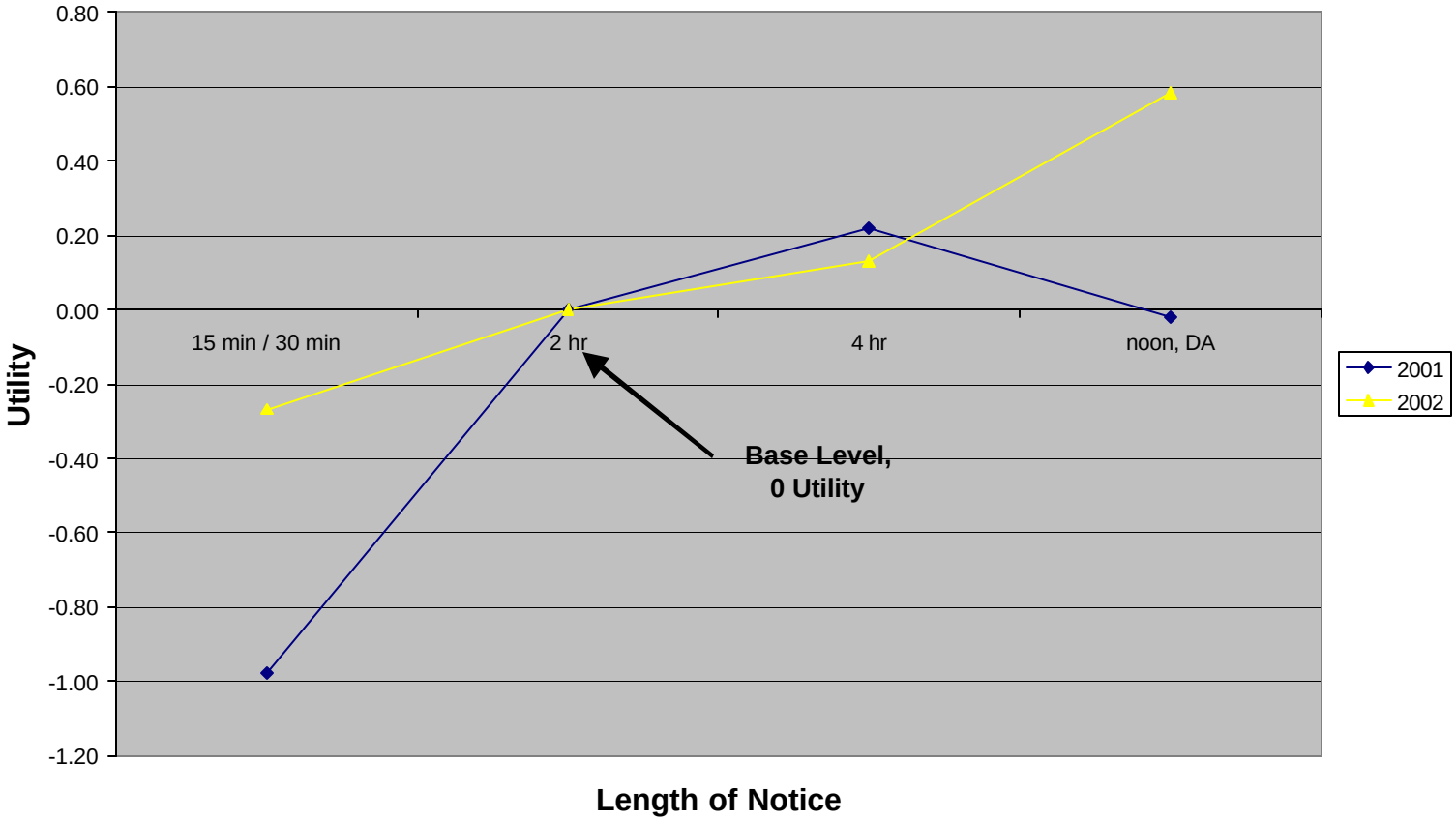


Fig. 4-34: Relative Utility Levels of Notice Periods for PRL Non-Participants

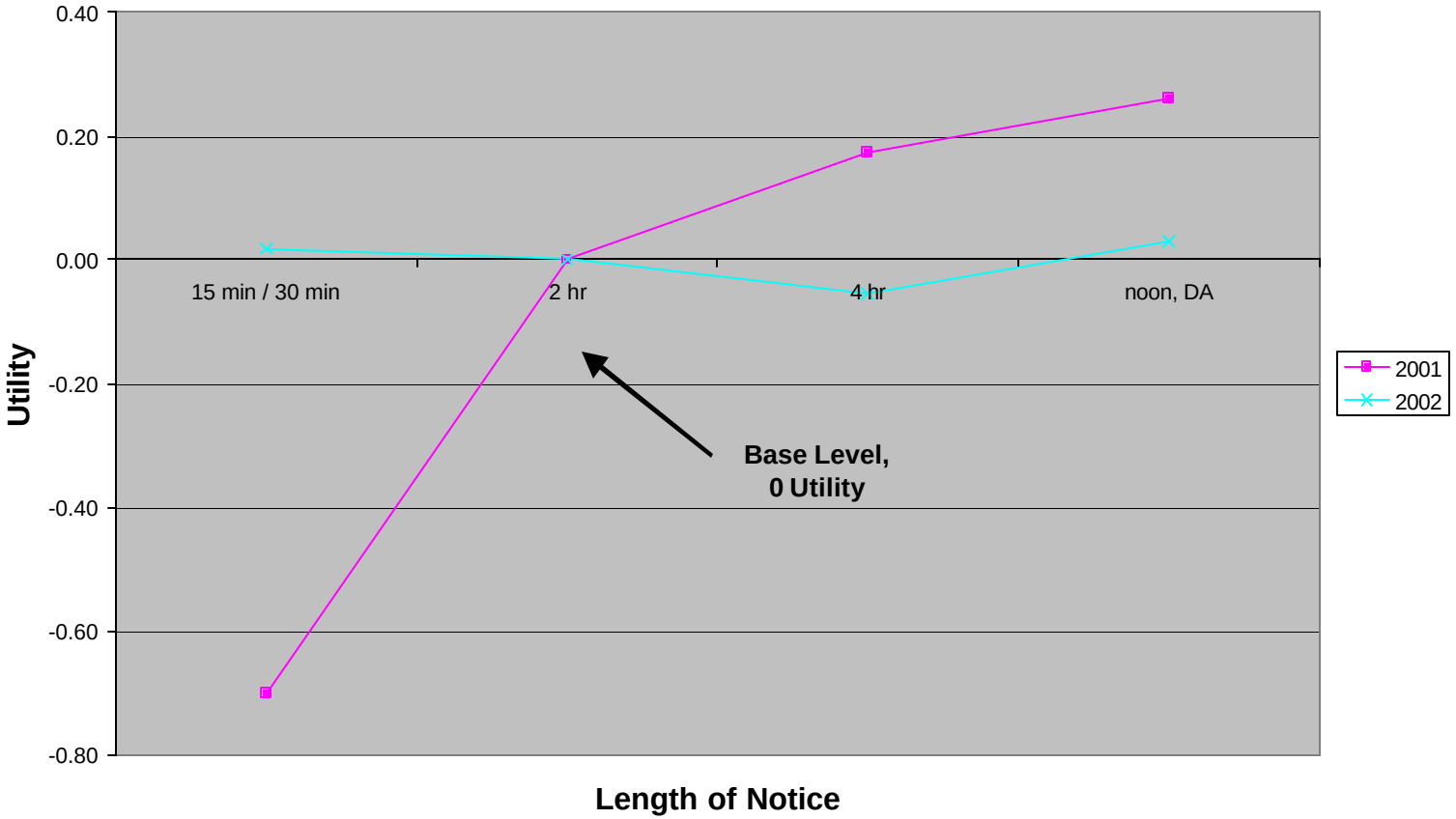


Fig. 4-35: Relative Utility Levels of Event Durations for PRL Participants

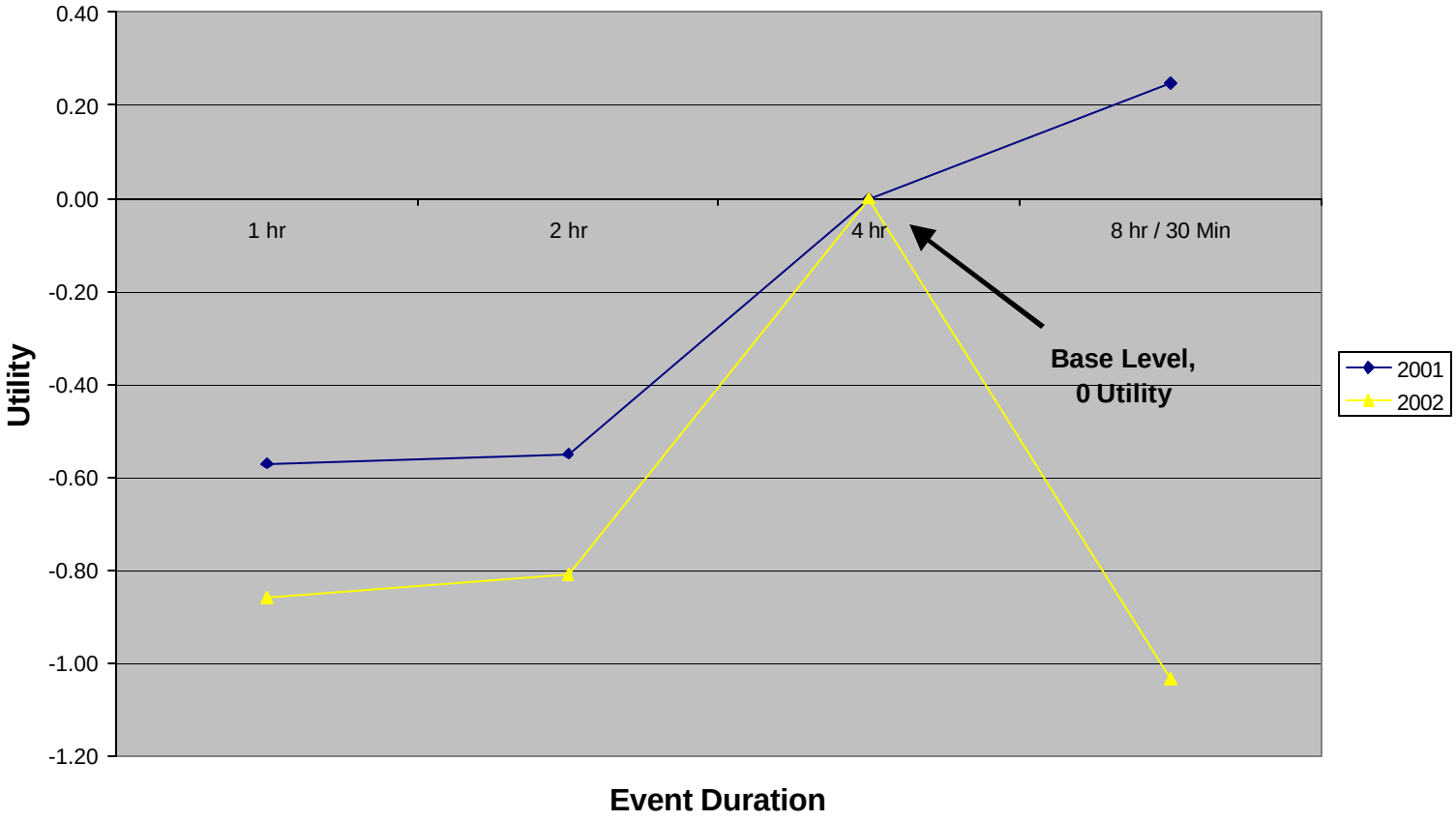
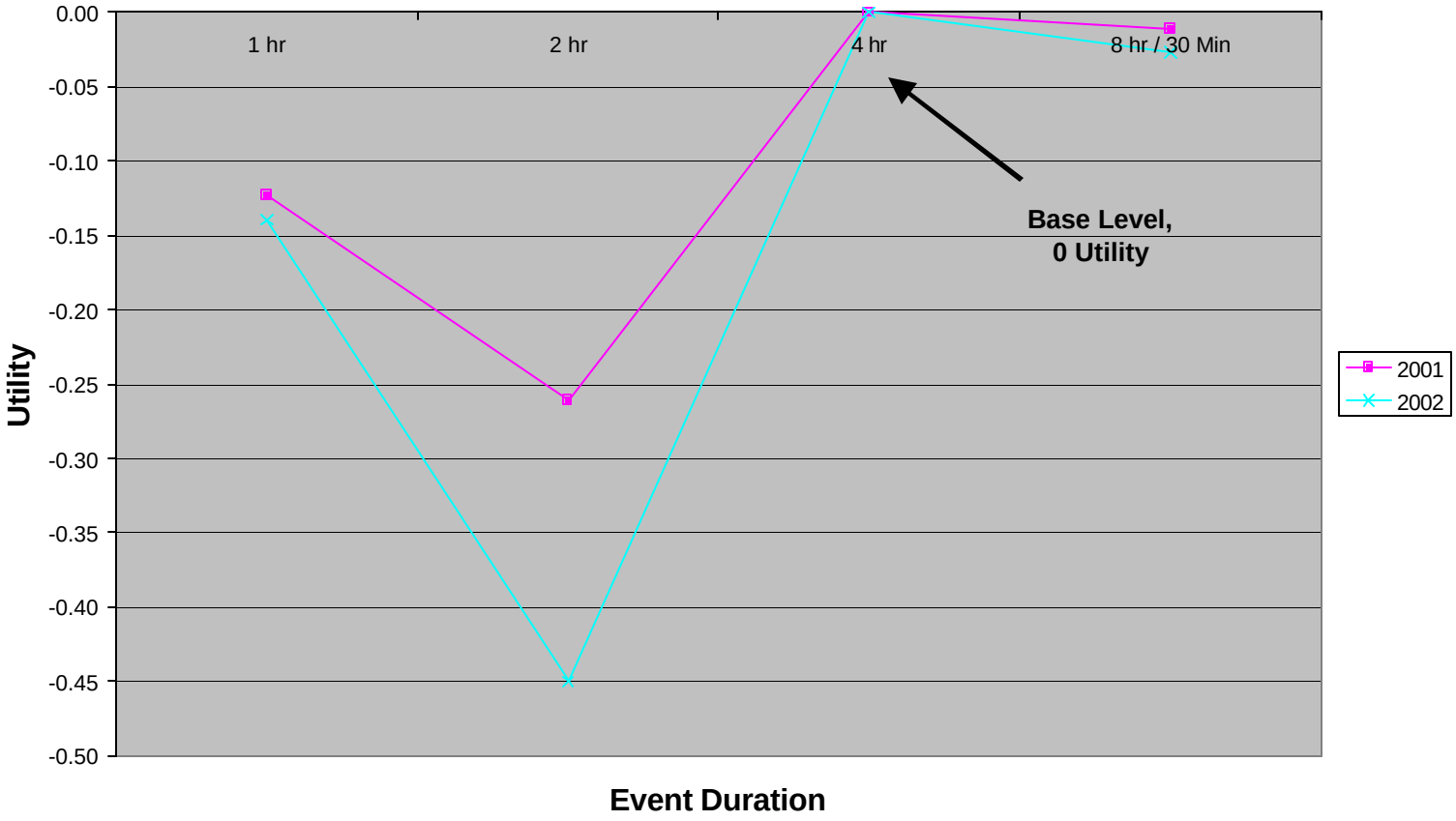


Fig. 4-36: Relative Utility Levels of Event Durations for PRL Non-Participants



Chapter 5 - Implicit Price Elasticities of Demand for Electricity and Performance Results

Overview

A comprehensive evaluation of NYISO's PRL programs would be inadequate without characterizing how well customers performed during PRL events. To accomplish this, we developed and estimated three alternative measures of performance for EDRP.[1] All the measures utilize customer's measured load reduction – the difference between their metered usage and CBL during event hours – as the basis for comparison.[2] The implicit price elasticity measures that load change relative to the prices the customer faces, evoking the usual interpretation of price elasticity. This metric is useful for extrapolating the performance to situations where the inducements to shift are different than what the current programs offer. This year's results are compared to those of last year to provide insight into how performance is changing as the Emergency Demand Response Program (EDRP) grows and matures.

Two additional performance indices, the Subscribed Performance Index (SPI) and the Peak Performance Index (PPI), are developed to provide a metric for comparing customer performance relative to what they said they could do when they subscribed, and relative to their peak usage level, respectively. These metrics allow comparisons of the curtailment yield between customers and among aggregations of customers. Yield is important to system operators that need to estimate the impact of dispatching PRL resources and to program marketers that, facing customer acquisition costs, desire to estimate the profitability of recruiting different customer segments and types.

The Chapter is organized as follows. First, we describe the three measures developed to measure curtailment performance. Then, we discuss the implicit demand elasticities, which are provided on an event, customer, and zonal basis. To help NYSERDA measure its contribution to the PRL program, the elasticities values of customers that received PON funding are compared to

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[1] Due to low bidding activity and the lack of sufficient participant-specific usage data, the measures discusses were not applied to DADRP.

[2] The CBL represents the customer's deemed usage, what it would have consumed during event hours if the event had not been called. The CBL is the average usage during the event hour in the five highest of the previous (to the event day) ten days, excluding any event days.

those of the other EDRP participants. The discussion of performance then turns to the results of the SPI and PPI analyses.

Methods

Implicit Demand Elasticities

The neoclassical theory of the firm is based on the assumption that firms allocate factors of production in such a way as to achieve the profit maximizing output for the firm, given a prevailing set of input and output prices. Implicit in this theory is also the assumption that, for a given set of input prices, factors are allocated by firms in such a way as to produce the appropriate profit maximizing level of output at minimum cost (Ferguson, 1969).

It can be further established that the demand curve for any input or factor of production in the short run is the value of the marginal product (VMP) schedule for that factor. Each value on the VMP schedule represents the marginal product of the input (the additional output that can be produced with an additional unit of an input, all else constant) *multiplied* by the price of the output. This places a dollar value on the additional output produced by the extra unit of input. Thus, the VMP schedule indicates the value to the firm of marginal additions to or subtractions from any given input level.

To summarize, by using an input up to the point that its value in production (e.g., the value of the marginal product) is equal to the price of the input, the firm's profit is maximized. Because of the law of diminishing marginal productivity, if the firm uses fewer than the profit maximizing level of input units, some profit is forgone because the value of the additional output from using the additional unit of input is above the cost of the input. On the other hand, if inputs in excess of the profit-maximizing level are used, the value of the additional output forthcoming from the last unit of the input is below the price of the factor, and profit falls. Profit would be higher by not using this last unit of input. Knowing the demand curve for the firm's inputs provides the means for ascertaining the optimal level of input use. The demand curve also provides the means for ascertaining how input levels would change from any given level as input prices change. These fundamentals provide the basis for measuring how customers respond to changes in electricity prices, and a means for measuring relative price responsiveness.

Simple representations of two separate demand curves (VMP_E) for electricity are shown in Fig. 5-1. Assume that one of these curves characterizes the demand for electricity as viewed by

a firm participating in NYISO's DADRP. This curve is labeled $VMP_{E|DADRP}$, and it represents the amounts of electricity that will be demanded at various prices in real time as long as the price the firm is charged (or is paid to curtail load) is known a day in advance. The other demand curve (labeled $VMP_{E|EDRP}$) is assumed to be the demand curve for electricity by the same firm in real time, for prices that are not known until real time. This second demand curve reflects the situation of a firm participating in EDRP. In both cases, as the price of electricity rises, the demand for electricity will fall.[3]

The significant difference in the two curves is that the one corresponding to the demand in real time under EDRP is steeper than the one for the day-ahead market. The reason for the difference is that if a firm is participating in DADRP, it has 24 hours to make necessary adjustments to minimize the effect of a reduction in electricity usage. In the case of EDRP, the customer is informed only two or so hours before it must reduce electricity usage; the firm has less time to make adjustments that can minimize the effect on the firm's production, and generally is less capable of altering its economic activity. Unfortunately, insufficient data are available on DADRP participant usage to estimate the underlying demand curve, so we are not able to compare the performance differences implied in the Figure.

In the customer representation of electricity demand depicted in Fig. 5-1, we assume that the firm plans to consume electricity at the level represented by the CBL and at its current rate of P_B. This rate could be a flat $/kWh charge, it could involve demand and energy charges, or it could be comprised of peak and off-peak TOU-type pricing. But, what level would it operate at if an EDRP event were called and it were offered $500/MWH to reduce load?

Given the profit maximizing argument introduced above, if the firm is going to participate in a PRL program and provide load reduction (represented in Fig. 5-1 as the change in usage from CBL to L_R) the firm would respond along the steeper curve $VMP_{E|EDRP}$. This load reduction would only be forthcoming at a payment level of P_E, which, as illustrated in Fig. 5-1, is substantially higher than P_D. What causes these differences in how customers respond to prices, and how can price responsiveness be measured?

In more precise economic terms, the elasticity of factor demand is defined formally as the percentage change in demand for a factor when the price of the factor is changed by one percent.

[3] In this analysis, we assume that customers face a predetermined price schedule or rate and that, on occasion, that rate is supplemented with DADRP or EDRP curtailment prices that are several times higher.

In practical terms, the elasticity of demand is calculated as the percentage change in demand for a factor divided by the percentage change in the price of that factor. This elasticity, as with all demand elasticities, is expected to be negative – for as the price of the factor increases, demand for that factor will decrease.

These elasticities of demand can be calculated from program participant data during EDRP program events.[4] Although they are consistent with the performance data, we refer to them as arc or implicit elasticities because they are calculated as the simple algebraic differences in usage that are put in percentage terms by dividing by the beginning CBLs and baseline rates. The estimates are not based on a systematic econometric modeling of repetitive behavior due to price differences for programs in which customers have participated for some extended period of time. Because implicit elasticities are calculated from only a few observations, and because the formulation does not take into account other factors that influence price responsiveness, they are generally regarded as representing only local behavior. In other words, they reflect changes that are associated with price changes very close to those upon which they were calculated. In this case, it means that the elasticities are likely to be accurate for EDRP prices that are close to $500. But, for prices that vary substantially from that level, for example a price of $100/MWh or $1,000/MWh, they may either over- or under-estimate the quantity change. Despite these cautions, the empirical estimates reported below are consistent with more formal analyses conducted elsewhere, and on this basis, the results are very encouraging.[5]

To estimate this elasticity from EDRP performance data, we define the following terms:

CBL = the customer baseline load (the level of load the participant would otherwise consume under its standard tariff rate or its supply contract);

P_B = the participant's standard or contract rate;

P_E = the payment rate received by the participant for load curtailment in EDRP;

P_D = the payment rate received by the participant for a DADRP bid; and

L_R = the load served during the load reduction EDRP event.

CBL - L_R = the load reduction provided in response to EDRP or DADRP payment.

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[4] In the discussion that follows, elasticity and factor elasticity are used interchangeably.

The firm's elasticities of demand for electricity under EDRP, corresponding to the factor demand illustrated in Figure 5-1, is now defined as:

$$(1)\quad E_{(EDRP)} = \{[(L_R - CBL) / CBL] \div [(P_E - P_B) / P_B]\}$$

The data required to estimate this elasticity for each participant are the measured load during the event, the event CBL, and the EDRP curtailment payment level, all of which are available from the NYISO program database. In addition, we need to specify the rate each customer would otherwise have paid for load consumed during the event, which we refer to as the background rate. Because most EDRP participants are served under a default provider (regulated LSE) tariff, we used utility tariff rates to develop an average cost of electricity value for customer types that reflected the size differences characteristic of these rates. Because in many cases the average rate is very sensitive to the underlying load shape, due to demand ratchets and other non-linearities in the rate schedule, the elasticities are likely underestimated.

Performance Metrics: SPI and PPI

An alternative characterization of participants' performance focuses on their actual load reductions delivered during emergency events compared to their subscribed load reduction and non-coincident peak demand, absent any adjustment for relative prices. For this analysis, we define two performance indices, called the Subscribed Performance Index (SPI) and Peak Performance Index (PPI), that can be used to characterize and compare program participants' actual response and technical potential to respond to ISO system emergency events.[6]

The Subscribed Performance Index (SPI) is the ratio of load reduction delivered versus load reduction subscribed. It can be interpreted as a measure that expresses how well a customer or a portfolio of customers performed compared to their pledges, how reliable is their pledge to curtail. This measure is of interest to ISO operators as a way to gauge the reliability of this dispatchable resource based solely its subscription pledge, before actual performance is observed.

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[5] See for example, Herriges, *et al*., 1993; Caves and Christensen, 1980 and Long, *et al*., 2000; Braithwait, 2000; and Patrick, 1990).

[6] Technical potential in this discussion refers to the physical aspect of a participant's ability to curtail load, regardless of the economics of doing so.

We define the Subscribed Performance Index (SPI) in two ways to provide alternative perspectives on the reliability of EDRP resources. One index applies to individual customers, and the other to a portfolio of customers.

The customer-specific subscribed performance index, SPI_c:

(2) $SPI_c = (E_{avg} / E_{sub}) \cdot 100\%$,

where

(3) $$E_{avg} = \frac{1}{N}\sum_{t=1}^{N}(CBL_t - E_{actual,t})$$

and

N = the number of hours per curtailment event,

$E_{actual,\,t}$ = the facility electric energy in hour t [MWh],

CBL_t = the customer baseline in hour t [MWh], and

E_{sub} = the subscribed load curtailment as provided for each participating customer by NYISO. It is nominated in electric capacity units (MW) delivered for each hour of the curtailment period. Thus, the resulting quantity is an energy measure expressed in MWh.

The subscribed performance index for a portfolio of customers, SPI_p:

(4) $SPI_p = (E_d / E_s) \cdot 100\%$,

where

(5) $$E_d = \sum_{i=1}^{M}\left(\sum_{t=1}^{N}(CBL_{i,t} - E_{i,t})\right),$$

(6) $$E_s = N \cdot \sum_{i=1}^{M}(E_{sub,i}),$$

and

E_d = the total electric energy curtailment delivered by all customers in a program,

E_s = the total electric energy curtailment subscribed by all customers in a program,

CBL_t = the customer baseline of customer i in hour t [MWh],

$E_{i,\,t}$ = the electric energy of customer i in hour t [MWh],

M = the total number of customers in a program,

N = the number of hours per curtailment event, and

$E_{sub,i}$ = the subscribed load curtailment of customer *i* [MWh].

The SPI is analogous in some sense to the capacity factor assigned to generation, which represents its electric output relative to its design potential. However, unlike generation units that can be expected to perform close to their nameplate rating, customer estimates of their ability to curtail under program circumstances are likely to be somewhat speculative, especially for new participants.

The second performance measure is the Peak Performance Index (PPI), defined as the customer-specific ratio of their average delivered load reduction divided by their non-coincident peak demand. We formally define PPI as:

(7) $PPI = P_{avg} / P_{peak}$,

where

(8) $$P_{avg} = \frac{1}{N}\sum_{t=1}^{N}(CBL_t - P_{actual,t})$$

and

N = the number of hours per curtailment event,

$P_{actual,\,t}$ = the facility load in hour *t* [MW],

CBL_t = the customer baseline in hour *t* [MW], and

P_{peak} = the non-coincident facility peak demand [MW].

The PPI is a useful measure for characterizing the relative technical potential of a customer or a group of customers because its upper value of 1.0 equates to a virtually full shut down. The non-coincident peak represents the customer's highest usage level. Thus, in any event, it can never curtail more than that amount and the PPI is bound from above by a value of 1.0. The SPI is not so constrained. For example, a customer with a PPI of 1.0 indicates that it shed 100% of its facility peak demand during the curtailment period. The PPI can be utilized for identifying barriers and/or additional resource potentials. Market segments with low PPI (e.g., 5%) imply that these customers currently have few load curtailment opportunities and could potentially be targeted for additional technical assistance, education/information, or deployment of more advanced enabling technologies, etc. PPI values, combined with customer size, also provide insights into relative load curtailment potential of acquiring different types of customers.

Because the performance data as provided by the NYISO were expressed in hourly MWh terms, we substituted the power units in the PPI definition above with hourly energy units.

Furthermore, P_{peak} was determined using the maximum hourly CBL load as a proxy for the non-coincident facility peak demand, because customer load profiles were not available.[7]

Implicit Demand Elasticities Results

Using the algebraic form of equation (1), implicit demand elasticities can be calculated for participants using the NYISO EDRP program data that include the CBL, the load reduction, and the price paid for curtailments.[8] We estimated elasticities for those EDRP participants that indicated that they intend to respond to curtailment calls by reducing their usage; we excluded firms whose registration indicated that they intended to use on site generation to achieve a curtailment. With the limited data available, it was not possible to disentangle the separate influences underlying curtailments from those participants offering both to reduce usage and to operate on-site generation. For this reason, our analysis is limited to only a subset (906) of the total 1,711 participants in EDRP (Table 1-18, Chapter 1).

To calculate the implicit elasticities for individual load-curtailing EDRP participants, background electricity rates were derived from published rate schedules.[9] To protect the confidentiality of customers, we do not report elasticities for individual PRL participants. Instead, we provide the range in firm-level elasticities as well as the average elasticities across firms by pricing zone.

Calculated Implicit Demand Elasticities for Electricity

The average estimated implicit factor demand elasticities for 906 EDRP participants that curtailed load, by NYISO pricing zone, are given in Table 5-1, along with the load, CBL and load reduction data that went into their calculations. The curtailment data are for EDRP events called

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[7] Given that system events occurred on two hot summer days (July 30 and August 14), using CBL as a proxy for non-coincident facility peak demand is reasonably accurate for weather-dependent building loads, and somewhat more questionable for businesses whose loads are less weather-dependent (e.g., manufacturing, industrial facilities).

[8] In this analysis, we assumed participants were paid the full amount that the NYISO paid out. In many cases, participants likely received less than this amount as a result of sharing arrangements with their LSE/CSP broker. There was no way to ascertain what these arrangements might have been. But, lowering the price they receive would lower their response, and consequently the elasticity estimates we calculate here would be too high.

[9] Background rates were derived for each LSE and were assigned to all PRL participants located in that LSE's territory. Such rates were derived assuming a 500 kW demand and 60% load factor usage profile for a summer month.

on July 30 and August 14, which included the hours of 1:00 to 6:00 p.m. on both days.[10] The elasticity estimates are based on the minimum price guarantee of $500/MW for the EDRP program for the summer of 2002.[11]

The average zonal elasticities in Table 5-1 and the zonal elasticity ranges and standard deviations in Table 5-2 are based on the percentage reductions in load that are calculated as the difference between the customer's total load over all hours of all event days and its total CBL over all event hours of all event days. This strategy assumes that for event days that are reasonably close together, customers would respond in a similar fashion. This seemed an appropriate assumption after examining the data.

During the EDRP event hours, the EDRP participants included in this analysis consumed a total of 5,941 MWH of electricity, and their corresponding combined CBL was 8,978 MWH (Table 5-1). Thus, the total load relief for these customers was 3,037 MWH over the two event days. This amounts to a 33.8% reduction in the average typical usage, as measured by the difference between the participant's hourly CBL and its actual event usage, in response to the EDRP curtailment call. This is two percentage points higher than the value calculated for participants in the 2001 events (Neenan Associates 2002). By zone, these reductions ranged from a low of about 9.6% in zone G to a high of 58% in zone A.

Relative to the customers' base electricity rates, the *average* calculated price elasticities of demand by customers in the various NYISO pricing zones ranged from a low of - 0.02 in zone G, to a high (in absolute value) of - 0.16 in zone H (Table 5-1).[12] This range begins at a slightly higher level than for the analysis in 2001, and the top end is slightly higher as well. However, the overall average is, -0.03 (Table 5-1), considerably lower than the –0.09 average from 2001 (see Neenan Associates 2002, Table 2-1). One compelling explanation for this result is that the customers finding the most value in EDRP last year probably enrolled in 2002, and perhaps performed slightly higher. Whereas the new participants in 2002 are predominantly customers

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[10] Elasticities were also estimates for two event days in April 2002. Due to low participation in these early-season events, we report the results separately in the Appendix.

[11] Even though customers in some event hours were paid LBMPs above the $500 price guarantee, these prices were not known at the time of curtailment. Therefore, we assumed that the price on which these load reductions were based is the minimum price guarantee.

[12] The elasticity is expected to be negative in sign because load and price should move in opposite directions. ,

with somewhat more limited capacity to respond. This is particularly likely for the several hundred small commercial and residential customers enrolled by LIPA, which comprised a large portion of the overall enrollment increase.

Despite this difference between the two years, these elasticities are still consistent with response elasticities found in more formal price response studies of customers participating in real-time and TOU pricing programs. Moreover, there is substantial variation in these elasticities about the mean (Table 5-2). Some individual participants' implied response elasticities are as large as - 0.47, while several are in the neighborhood of - 0.23. This firm-level variation reflects differences in the ability and willingness of customers to respond on certain days.

For the 23% of customers exhibiting small positive price elasticities (up from the 11% of 2001) on average (Fig. 5-3, first bar), the implication is that usage was on average above the CBL during the events. These customers either found it impossible to curtail load, or in attempting to comply they misjudged their CBL, and usage inadvertently remained above the CBL in the aggregate, even though they may have actually curtailed some electricity usage in response to the call.[13] Again, the large number of smaller, new entrants accounts for the reduction in the overall portfolio performance. This is to be expected as program enrollment reaches out into new customer segments that offer lower curtailment levels, but add valuable diversity.

The estimated implicit elasticities of response varied considerably by the size of a firm's average electricity usage (Fig. 5-4). Because of the large number of LIPA customers this year, the majority of the participants in EDRP had loads below 250kW. Most customers also exhibited low (elasticities greater in algebraic value than - 0.05) to modest (elasticities between – 0.05 and – 0.20) price response.

Although participants with low elasticities dominate all size classes, as electricity consumption levels increase, so did the percentage of participants in that size category with moderate to high elasticities of response (elasticities between – 0.05 and – 0.20 and greater than - 0.20, respectively). This observation is consistent with the belief by some that larger customers have better knowledge of their load shapes, and are thus better able to respond during curtailment

[13] The CBL is derived from average usage on previous, no EDRP event days. To the extent that the CBL is not representative of what customers would have actual used, because of weather or other effects, then customers may have found that curtailing was not profitable because they would not receive full credit for the actions they undertook. Moreover, there is no penalty for noncompliance, so some customers may have sighed up speculatively, only to find that they could not curtail when an EDRP event were called.

opportunities. The results also show that firms with an average hourly load under one MW generally did not appear to be as responsive as their larger counterparts. These smaller customers may be inherently less capable of curtailing usage under EDRP terms, or they may simply need more education concerning their load shape and assistance on load management strategies to become more effective in reducing load during EDRP events.

Conventional wisdom would also suggest that the performance of EDRP load reduction resources would drop off substantially toward the end of emergency events, especially if the events last for several hours each day and are called over a number of consecutive days as well. Conversely, for those participants with on-site generation, one might also expect that this "fatigue factor" would be minimal, or perhaps non-existent, given these customers' abilities to simply turn on a generator at the event start time and leave it on for the event's entire duration. In contrast to this conventional wisdom, however, it appears that most EDRP participants without on-site generation are more reliable in their load curtailment contribution once they committed to the EDRP event (Fig. 5-5).[14] Although there is some decrease in the overall curtailment level of load reduction resources as each event day progressed, for the most part, load-curtailing participants were able to sustain their load reduction efforts throughout these 5-hour events. Load relief was substantially above the mean in hour 15 on the second day (August 14), which is due to participation of a large resource aggregation for only one-hour. Thus, after taking this into account, load reductions were quite consistent across all hours on the two days, although curtailments on August 14 got off to a slower start than they did on July 31.

Demand Elasticities for NYSERDA vs. Non-NYSERDA Participants

Among summer 2002 EDRP participants, 102 (11%) of the 906 customers for which we estimated elasticities also received funding and completed projects through NYSERDA PONs offered in 2001 and 2002.[15] These NYSERDA programs offered financial assistance to firms for the purchase of load reduction or load shifting technology and/or metering and communications equipment that could have affected customers' decisions to participate in EDRP and increased the amount of load reduction offered during curtailment events.

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[14] This persistence was even more remarkable last year because the events were scheduled on four consecutive days.

[15] NYSERDA provides funding to support customer participation on PRL programs through Program Opportunity Notices (PONs). See Chapter 7 for a description of these programs.

NYSERDA is interested in the performance of this subset of customers relative to the population of participants. To provide this comparison, we have prepared tables that break out elasticity estimates for two subgroups of customers: 2002 EDRP participants in a NYSERDA program (Tables 5-3 and 5-4), and 2002 EDRP participants that did not participate in a NYSERDA program (Tables 5-5 and 5-6).

The average price elasticity of demand for customers in the NYSERDA subgroup is - 0.07 (Table 5-3), over twice as high as the level for other participants, - 0.03 (Table 5-5). The distributions of these implicit elasticities for each subgroup are displayed in Figs. 5-6 and 5-7, respectively. At the zonal level, these average response elasticities ranged from zero in zones K and G to – 0.16 and – 0.17 in zones H and I, respectively, for the NYSERDA participants (Table 5-3). The individual firm elasticities ranged from – 0.47 in zone J to 0.05 (load actually went up during events) in zone A (Table 5-4). For the non-NYSERDA participants, the zonal averages range from a positive 0.13 in zone F to - 0.12 in zone D (Table 5-5). The individual firm elasticities for this sub-group range from – 0.47 in zone J to 2.67 in zone F (Table 5-6). Based on these results, NYSERDA is in fact achieving its goals of improving the performance of the PRL portfolio.

SPI and PPI Results

SPI for NYSERDA vs. Non-NYSERDA Participants

At the time they enrolled in EDRP, customers were asked to provide an indication of the amount of load reduction they anticipated being able to supply during an EDRP event. The program required that they be able to curtail at least 100 kW.[16] In Figs. 5-8 (Daily) and 5-9 (Zonal), we provide comparisons of these initial "subscribed load reduction capacities" to customers' actual average curtailment performance, aggregated over the entire portfolio of customers (SPI_p). The ratio of average actual and subscribed performance (SPI_p) was very consistent, 44.5% on the August 14 and 44.8% on July 30.

As described above, two SPI performance measures were developed. The aggregate index characterizes the EDRP resources as a collective resource, and as such represents an average characterization of performance. The customer SPI index preserves the individuality of

[16] Customers were allowed to aggregate their load(s) with others and subscribe as a single entity to meet this requirement.

performance, and therefore betters characterizes the dispersion of performance among participants.

The aggregate performance of the portfolio of NYSERDA participants, relative to their initial subscription levels, is higher than for the portfolio of other participants. Over the two event days, NYSERDA's participants delivered an average of 53% of their initial indicated subscription amount, and exhibited very low variability, with values ranging from 50.1% to 54.7% of subscription amounts over the two days. This performance was well above the 45% for the non-NYSERDA subgroup. One explanation for this result is that NYSERDA funding provided for greater attention to up-front curtailment capacity auditing, so these customers better understood what they could deliver by way of load curtailments when they registered for EDRP.

In Fig. 5-9, we provide comparisons of these initial "subscribed load reduction capacities" to customers' actual average curtailment performance, aggregated by zones. In some zones participants in NYSERDA programs outperformed the others, while in some zones the reverse was true. Only in zones B, and G did the non-NYSERDA customers significantly "outperform" those who had participated in a NYSERDA 2002 PON.[17] One would clearly have to know more about which NYSERDA programs were implemented in the various zones and the types of customers to explain these zonal differences. Moreover, the character of the participants may also account for the difference, in that the non-NYSERDA customers in those zones may have had more prior experience with load management, or be better endowed naturally to curtail under EDRP provisions.

Fig. 5-10 compares the individual performance of NYSERDA and non-NYSERDA customers by curtailment strategy (i.e., load reduction only vs. on-site generation). On average, NYSERDA participants that relied on load reduction strategies as their curtailment choice significantly outperformed the non-NYSERDA participants, as indicated by the SPI_c of 73% for participants vs. 42% for others. NYSERDA participants who relied on on-site generation to reduce their load did not perform as well as non-NYSERDA participants (SPI_c of 58% vs. 41%). Note that many of the NYSERDA projects were only recently completed, which may have contributed to a lack of readiness to participate during the summer 2002 NYISO system emergency events. However, the specific reasons for the lower SPI_c performance of NYSERDA

[17] There are no NYSERDA participants in zone K.

vs. non-NYSERDA participants using onsite generation are difficult to ascertain and would require individual interviews with the customers.

Customer Performance by Market Segment

We were also interested in understanding customer performance by market segment and type of business activity. Based on SIC code information, we grouped customers into various business types and, using SPI_c values calculated for individual customers, reported the average SPI_c values, total subscribed load reduction for active participants, and total subscribed load reductions for all participants, segmented by type of businesses and load curtailment strategy (Fig. 5-11). For each group of participants corresponding to a particular load curtailment strategy and business type, we report average SPI_c values only if we had actual performance data for at least five customers in that group. In general, the information in Fig. 5-11 can help NYSERDA program managers target technical assistance, incentives, and/or information to sectors where actual performance lags behind subscribed goals. It also provides insights to NYISO system operators on the likely responses of different types of customers and businesses to system emergencies.

The important specific findings resulting from this analysis are as follows:

- Government and health facilities that utilized on-site generation to curtail loads had average SPI_c values in the 60-80% range. In contrast, the average SPI_c values were more variable among business types that only relied on load reduction strategies. For example, the average SPI_c value was ~65% among manufacturing customers, which comprise the largest single market segment (502 MW of subscribed load reductions among performing customers) of the population of participants. Based on customer survey data, many manufacturing customers shut down entire processes or specific equipment for the duration of an emergency event and resume production at night or the next day. These manufacturing customers tend to be sophisticated energy users with knowledge of their equipment and process loads, which may explain the higher performance values.
- Facilities owned by government agencies and various types of utilities (e.g., telecommunications, water) that actively participated in EDRP events provided a significant contribution of about 90 MW of subscribed load reduction and performed at a relatively high level, with an average SPI_c of 80%. These facilities often have on-site energy managers and well-developed load curtailment plans that explicitly involve

employees, have been involved with demand-side programs for several years, and some have a tradition of participating and providing "voluntary" load reductions during system emergencies.

- Office buildings, recreational facilities and casinos, and educational institutions curtailed load above their subscription targets (i.e., average SPI_c >100%), which suggests that these facilities have greater curtailment capability than they foresee, and in fact represent a value pocket of EDRP resources. However, this result should be interpreted with caution because of small sample size.
- Many educational facilities did not perform at all (e.g. 30 MW total subscribed but only 9 MW subscribed from active customers), although those relatively few facilities that were active in the program performed quite well (SPI_c = 108%).
- Multi-family apartments and health care facilities had average SPI_c values in the 25-40% range and were relatively poor performers. Multi-family apartments generally lack diversity in their load management strategies, with reliance on thermostat reset option or shutting off lights, which are heavily dependent on occupant behavior and difficult to predict. Hospitals and other health care facilities are limited in their load reduction strategies without the support of backup generation. Maintaining clean and comfortable indoor air conditions for health care patients and occupants is of utmost importance and generally cannot be compromised, which may leave relatively few options to curtail loads in order to meet subscription levels. Thus, limited by stringent thermal comfort constraints, health facilities have limited load reduction opportunities aside from on-site generation, which is the dominant curtailment strategy in that sector (8.6 MW of generation vs. 3.1 MW of load reduction).

We also examined average performance of customers of different business types compared to their technical potential (i.e., the Peak Performance Index; see Fig. 5-12). On average, government and unclassified facilities that relied on on-site generation strategies reduced their load by about 50-55%, relative to their CBL. In health care facilities, back-up generation systems were smaller compared to facility load, on average, or were used much more sparingly by these customers, indicated by an average PPI of ~15%. Customers curtailing load in certain types of businesses, such as government/utility facilities, manufacturing, recreational facilities/casinos, and commercial offices, also achieved relatively high PPI values in the 30-40% range. This performance goes against the conventional wisdom that only manufacturing firms are

willing to curtail a substantial portion of their electricity usage on short notice. However, for some types of businesses, such as commercial offices and recreational facilities, sample sizes are small; thus results should be interpreted with caution. On average, educational facilities that performed reduced loads by about 20%, while health care facilities reduced usage by less than 10%, compared to their CBL during curtailment events.

Impact of ICAP-SCR Participation on EDRP Performance

Customers in EDRP also have the option of enrolling in the ICAP/SCR program. EDRP/ICAP-SCR participants receive the market value of ICAP but face penalties for non- or under-performance that can exceed the up-front payment. In order to examine the impact of program choice and load reduction strategy on curtailment performance, we grouped customers into EDRP-only participants and EDRP/ICAP-SCR participants and then segmented them by their load reduction strategy (Fig. 5-13). On average, EDRP/ICAP customers had SPI_c values in the ~90-95% range for both load reduction only and on-site generation strategies during the summer 2002 events. These results suggest that EDRP/ICAP customers, irrespective of load reduction strategy, are reliable performers in terms of meeting their subscribed EDRP targets.[18]

On average, EDRP-only customers that utilized load reduction only or onsite generation had SPI_c values of 49% and 41%, respectively, which provides a good overall indicator of actual performance in a voluntary program with no penalties. It is worth noting that even though joint enrollment in EDRP/ICAP is much lower than EDRP only (113 vs. 1105 customers with performance data), the subscribed load reductions among performers are comparable (455 MW vs. 429 MW). On average, joint EDRP/ICAP-SCR customers subscribed individually about 10 times the load curtailment than did customers who subscribed to EDRP only (4 MW vs. 0.4 MW), which suggests that the ICAP program attracts larger customers.

EDRP Resource Performance Curve

Fig. 5-14 provides some insight into the overall distribution of individual customers' SPI_c performance across the resource base comprised of all EDRP participants. In this figure, we include only those customers that reported any load reduction in at least one hour during the July

[18] Because performance is measured on different metrics, an SPI of less than 100% does not indicate noncompliance with the ICAP/SCR curtailment obligation.

and August events. This adjustment gives a total resource base of 878 MW for active program participants compared to the total subscribed load enrolled in EDRP of 1477 MW.

About 211 MW (24%) of subscribed load performed at or above their subscribed load curtailment pledge (SPI_c >100%). These customers underestimated their curtailment capabilities or were overly cautious in determining their subscribed load reduction target. The remaining 76% of the EDRP resources (667 MW) performed at or below their pledged curtailment levels. By adjusting the subscribed curtailment with the customer's SPI_c performance, we can estimate the full-performance resource equivalents to be about 564 MW. This corresponds to a de-rating factor of 0.64 (564/878 MW=0.64).

EDRP Resource Potential Curve

We also created an EDRP resource potential curve following an approach similar to that used to develop the EDRP resource performance curve (Fig. 5-15). This curve describes the relationship of individual customers' PPI to their subscribed load and characterizes the relative ability of the active EDRP participant pool to curtail load on the electric system (i.e., PPI of 1.0). We aggregated the cumulative load reduction achieved by customers that pursued various load curtailment strategies (load reduction only, onsite generation, or load reduction plus onsite generation), along with the total resource potential curve, for active EDRP participants.

The subscribed load of active EDRP participants was 878 MW. About 42% (365 MW) of that subscribed load reduced their load by 80% or more (PPI > 80%) during the two event days. About 300 MW of the 365 MW load reduction from these customers was achieved by those employing load reduction strategies alone, which we believe was primarily attributable to manufacturing companies shutting down equipment or re-scheduling production processes, based on our customer survey research. The average load reduction among these customers was large: about 8 MW per customer, on average.

At the other end of the PPI spectrum, about 150 MW of subscribed load comes from hundreds of customers that reduced their CBL by less than 20%. This group consists predominantly of small to medium-sized facilities involved in retail and wholesale trade, education, government, health care as well as multi-family buildings. These customers relied primarily on load reductions, except for the health sector, which used small on-site generators combined with load reduction strategies. Typically, these customers either do not have, or chose not to utilize, on-site generation capabilities, and generally do not have remote or centralized

control capabilities. This figure shows the diversity of the EDRP resource potential base of active customers.

Summary and Conclusions

The EDRP program was invoked twice during summer 2002, on July 30 and August 14, with a total of ten curtailment hours. The performance data resulting from the two events provides a limited, yet insightful view into the performance characteristics of the participating customers, from which a number of observations and general conclusions can be drawn. We estimated implicit price elasticities of demand and two other performance metrics to analyze the performance of individual customers as well as the portfolio of customer load resources during system emergencies. Highlights of our analysis are summarized below.

Summary of Implicit Price Elasticity Results

- Price elasticities averaged by NYISO pricing zones ranged from a low value of –0.02 in zone G to a high of –0.16 in zone H.
- Across all zones the average price elasticity for the 2002 EDRP program is –0.03, which is considerably lower than the 2001 value of –0.09. The primary reason for this decrease in elasticity is assumed to be the participation of new entrants to the 2002 program that have limited capacity to respond. Participation in EDRP program increased from ~300 customers in 2001 to ~1700 customers in 2002; hundreds of the new participants are small commercial and residential customers.
- Price elasticities vary by customer size, with low elasticities averaged over all zones of less than –0.05 dominating for small and medium sized customers. High elasticity values of above –0.2 were reported for 15% of EDRP's large customers (>4 MW). This result is consistent with the notion that larger customers have better knowledge about their energy utilization pattern and technical capabilities to be able to respond during curtailment events.
- Participants in NYSERDA-funded PONs achieved a price elasticity over twice as high as the level estimated for EDRP participants that did not participate in a NYSERDA-funded PON (-0.07 for NYSERDA participants vs. –0.03 for non-NYSERSA participants).

Summary of Customer Performance Analysis Results

- The average actual load curtailment performance of the 113 EDRP participants that were also enrolled in the ICAP/SCR program was quite reliable (96% of their subscribed load reductions overall and greater than 90% for load reduction only and onsite generation curtailment strategies). It is assumed that the financial consequences of under- or non-performance for ICAP/SCR resources are a key driver underlying this high performance. In aggregate these 113 customers had a subscribed load of 455 MW, and thus accounted for 60-70% of the delivered load curtailment during EDRP events.
- On average, the 1105 EDRP-only customers delivered 42% of their subscribed load reduction commitment when called, which is a useful indicator of actual performance in a voluntary program with no penalties.
- On average, participants in NYSERDA-funded PONs out-performed non-NYSERDA customers relative to their subscribed load reduction commitment (average SPI_c values of 64% vs. 46%). This difference was even more significant for those participants that adopted load curtailment strategies (average SPI_c values of 73% for NYSERDA vs. 42% for non-NYSERDA). However, participants in NYSERDA-funded PONs that used on-site generation strategies did not perform as well as non-NYSERDA participants in EDRP, which may have been caused by a lack of readiness because many participants were new to EDRP in 2002.
- We also analyzed customer performance by business type and load curtailment strategy (e.g. load reduction only, on-site generation, load reduction plus on-site generation). Overall, actual performance compared to subscribed load reduction goals was more variable for those customers that relied on load reduction only vs. on-site generation. The group of manufacturing customers who actively participated in EDRP, comprising the largest single market segment with ~502 MW of subscribed load, performed reasonably well at 65% of subscribed load. Facilities owned by government agencies and various types of utilities performed quite reliably with their load reduction strategies (average SPI_c of ~80%) and represent a significant resource (90 MW of subscribed load from active EDRP participants).
- Several types of businesses or market segments appear to be under-represented in EDRP (e.g. commercial offices), or participants were not very active during summer events

(e.g., education facilities that may have been closed), or were relatively low performers (e.g. multi-family apartments, health care facilities). For these segments, additional technical and financial assistance, information tools, and/or increased utilization of "clean" on-site generation should be considered in order to improve performance and overcome and/or supplement limited load reduction opportunities.

- Government and health facilities that utilized on-site generation to curtail loads had average SPI_c values in the 60-80% range.
- The EDRP resource performance curve provides some insight on the overall distribution of performance across the entire base of active EDRP participants. We found that that 24% of the subscribed load performed at or above the subscribed level (SPI_c>100%). The full performance resource equivalence of the total subscribed load of 878 MW was 564 MW, equivalent to a de-rating factor of 0.64.
- The EDRP resource potential curve characterizes the relative ability of active EDRP participants to curtail load on the electric system through various load reduction strategies. We found that a relatively small number of large customers provided a significant contribution to the overall load curtailment resource with average load reductions of 8 MW. These customers, the majority of whom are manufacturers that shut down equipment or re-scheduled/halted production processes, reduced their usage by 80% or more, relative to their CBL, during EDRP events. Nevertheless, the EDRP resource base is quite diverse, as it also includes hundreds of small to medium-sized facilities spanning many types of businesses (e.g. trade, health care, education, government) and buildings (e.g., multi-family). Approximately 150 MW of subscribed load came from customers such as these, who reduced their usage by less than 20%.

The two analysis approaches highlight key findings. Large customers, many of whom are manufacturing facilities, have the ability to curtail and indicate the willingness to respond to curtailment events at high PPI levels while their performance remains high. A major contributing factor to high performance appears to be joint enrollment in ICAP/SCR program, which provides a steady revenue stream (e.g.. reservation payments) and financial consequences for under- or non-performance. We also identified market segments that are either under-represented (e.g. commercial offices), performed relatively poorly during events (e.g. health care, multi-family), or where a significant fraction of enrolled customers chose not to respond (e.g., educational facilities).

We have seen some erosion in the overall price elasticities between 2001 and 2002, which is assumed to be caused by a multitude of small new program entrants in 2002. This suggests that further downward pressure on performance can be expected if additional, smaller customers enter the program and shift the overall make-up for the resource pool toward smaller customers. However, comparisons of NYSERDA versus non-NYSERDA participants suggest that technical and financial assistance and deployment of enabling technologies, combined with targeted marketing, education, and information, can improve performance and increase participation among smaller customers.

Table 5-1. Average Zonal EDRP Event Performance by EDRP Customers in the Summer, 2002, All Event Hours

	Participants*		Load (MWH)		CBL (MWH)		At $500/MW Load Reduction (MWH)		Implicit Price Elasticity**	
Zone	Number	%	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
A	51	6%	27.6	50	65.8	114	38.18	90	-0.07	0.08
B	19	2%	10.1	24	15.2	34	5.08	11	-0.07	0.06
C	46	5%	10.4	21	14.4	29	4.04	19	-0.04	0.06
D	6	1%	1.8	2	2.5	2	0.72	1	-0.06	0.06
E	28	3%	7.2	8	8.8	10	1.59	4	-0.05	0.12
F	26	3%	16.5	32	29.0	48	12.52	30	0.04	0.54
G	6	1%	109.7	199	121.4	222	11.67	24	-0.02	0.02
H	4	0%	2.2	2	4.9	3	2.64	2	-0.16	0.05
I	13	1%	10.0	10	12.5	11	2.45	3	-0.10	0.12
J	40	4%	16.8	41	20.1	42	3.26	8	-0.08	0.11
K	667	74%	2.6	7	2.9	8	0.29	1	-0.03	0.05
Avg.##			**6.3**		**9.6**		**3.30**		**-0.03**	
Totals	**906**		**5,941**		**8,978**		**3,037**			

*These EDRP participants offered only load reduction. Those that supplied on-site generation, or both generation and load reduction are not included.

**These implicit price elasticities are calculated according to equation (3) above. See the text for more details of the calculations.

##These are weighted averages, weighted by the proportion of firms in each zone.

These load reductions are calculated by substituting the estimated price elasticities into equation (3) and solving for the reduction in load when P_E is set either at $250 or $750/MW.

Table 5-2. Implicit Price Elasticities by EDRP Customers, Summer, 2002

Zone	Participants	Implicit Price Elasticity of Demand			
		Minimum	Maximum	Average	Standard Deviation
A	51	-0.23	0.05	-0.07	0.08
B	19	-0.22	0.02	-0.07	0.06
C	46	-0.23	0.17	-0.04	0.06
D	6	-0.13	0.01	-0.06	0.06
E	28	-0.23	0.45	-0.05	0.12
F	26	-0.23	2.67	0.04	0.54
G	6	-0.04	0.00	-0.02	0.02
H	4	-0.23	-0.13	-0.16	0.05
I	13	-0.47	-0.01	-0.10	0.12
J	40	-0.47	0.02	-0.08	0.11
K	667	-0.21	0.13	-0.03	0.05

*These EDRP participants offered only load reduction. Those supplying on-site generation, or generation and load reduction are not included.

Note: See the footnotes to Table 5-1 for more details about the calculations.

Table 5-3. Average Zonal Performance by NYSERDA's EDRP Customers in the Summer, 2002, All Event Hours

	Participants*		Load (MWH)		CBL (MWH)		At $500/MW Load Reduction (MWH)		Implicit Price Elasticity**	
Zone	Number	%	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
A	24	24%	11.4	26	32.3	66	20.83	47	-0.07	0.09
B	7	7%	10.5	13	16.2	24	5.78	11	-0.05	0.05
C	32	31%	7.2	9	12.5	26	5.22	22	-0.04	0.04
D	4	4%	1.9	2	2.1	2	0.22	0	-0.03	0.04
E	4	4%	6.7	5	9.4	8	2.78	3	-0.09	0.07
F	10	10%	21.7	36	40.3	55	18.62	24	-0.10	0.08
G	0	0%	0.0	0	0.0	0	0.00	0	0.00	0.00
H	4	4%	2.2	2	4.9	3	2.64	2	-0.16	0.05
I	5	5%	6.8	7	10.7	8	3.83	4	-0.17	0.17
J	12	12%	28.4	73	32.9	75	4.51	9	-0.11	0.12
K	0	0%	0.0	0	0.0	0	0.00	0	0.00	0.00
Avg.##			**11.6**		**21.2**		**9.58**		**-0.07**	
Totals	**102**		**1,214**		**2,203**		**989**			

*These EDRP participants offered only load reduction. Those that supplied on-site generation, or both generation and load reduction are not included.

**These implicit price elasticities are calculated according to equation (3) above. See the text for more details of the calculations.

##These are weighted averages, weighted by the proportion of firms in each zone.

These load reductions are calculated by substituting the estimated price elasticities into equation (3) and solving for the reduction in load when P_E is set either at $250 or $750/MW.

Table 5-4. Zonal Implicit Price Elasticities for NYSERDA's EDRP Customers, Summer 2002

Zone	Participants	Implicit Price Elasticity of Demand			
		Minimum	Maximum	Average	Standard Deviation
A	24	-0.23	0.05	-0.07	0.09
B	7	-0.11	0.02	-0.05	0.05
C	32	-0.21	0.01	-0.04	0.04
D	4	-0.07	0.01	-0.03	0.04
E	4	-0.19	-0.04	-0.09	0.07
F	10	-0.21	0.01	-0.10	0.08
G	0	0.00	0.00	0.00	0.00
H	4	-0.23	-0.13	-0.16	0.05
I	5	-0.47	-0.08	-0.17	0.17
J	12	-0.47	-0.01	-0.11	0.12
K	0	0.00	0.00	0.00	0.00

*These EDRP participants offered only load reduction. Those supplying on-site generation, or generation and load reduction are not included.

Note: See the footnotes to Table 5-3 for more details about the calculations.

Table 5-5. Average Zonal EDRP Event Performance by Non-NYSERDA EDRP Customers, Summer, 2002

	Participants*		Load (MWH)		CBL (MWH)		At $500/MW Load Reduction (MWH)		Implicit Price Elasticity**	
Zone	Number	%	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.	Average	Std. Dev.
A	27	3%	42.0	61	95.6	138	53.60	115	-0.08	0.08
B	12	1%	9.9	29	14.6	40	4.68	12	-0.08	0.07
C	14	2%	17.5	35	18.8	36	1.35	3	-0.04	0.09
D	2	0%	1.7	0	3.4	1	1.73	0	-0.12	0.01
E	24	3%	7.3	8	8.6	11	1.39	4	-0.04	0.13
F	16	2%	13.2	30	21.9	43	8.70	33	0.13	0.68
G	6	1%	109.7	199	121.4	222	11.67	24	-0.02	0.02
H	0	0%	0.0	0	0.0	0	0.00	0	0.00	0.00
I	8	1%	12.0	11	13.6	13	1.58	2	-0.06	0.04
J	28	3%	11.9	12	14.6	14	2.72	7	-0.07	0.10
K	667	83%	2.6	7	2.9	8	0.29	1	-0.03	0.05
Avg.##			**5.7**		**8.2**		**2.50**		**-0.03**	
Totals	**804**		**4,728**		**6,775**		**2,047**			

*These EDRP participants offered only load reduction. Those that supplied on-site generation, or both generation and load reduction are not included.

**These implicit price elasticities are calculated according to equation (3) above. See the text for more details of the calculations.

##These are weighted averages, weighted by the proportion of firms in each zone.

These load reductions are calculated by substituting the estimated price elasticities into equation (3) and solving for the reduction in load when P_E is set either at $250 or $750/MW.

Table 5-6. Zonal Implicit Price Elasticities by Non-NYSERDA EDRP Customers, Summer 2002

Zone	Participants	Implicit Price Elasticity of Demand			
		Minimum	Maximum	Average	Standard Deviation
A	27	-0.23	0.01	-0.08	0.08
B	12	-0.22	0.00	-0.08	0.07
C	14	-0.23	0.17	-0.04	0.09
D	2	-0.13	-0.11	-0.12	0.01
E	24	-0.23	0.45	-0.04	0.13
F	16	-0.23	2.67	0.13	0.68
G	6	-0.04	0.00	-0.02	0.02
H	0	0.00	0.00	0.00	0.00
I	8	-0.13	-0.01	-0.06	0.04
J	28	-0.47	0.02	-0.07	0.10
K	667	-0.21	0.13	-0.03	0.05

*These EDRP participants offered only load reduction. Those supplying on-site generation, or generation and load reduction are not included.

Note: See the footnotes to Table 5-5 for more details about the calculations.

Fig. 5-1. Price Elasticities of Demand for Electricity: Equal Load Reduction

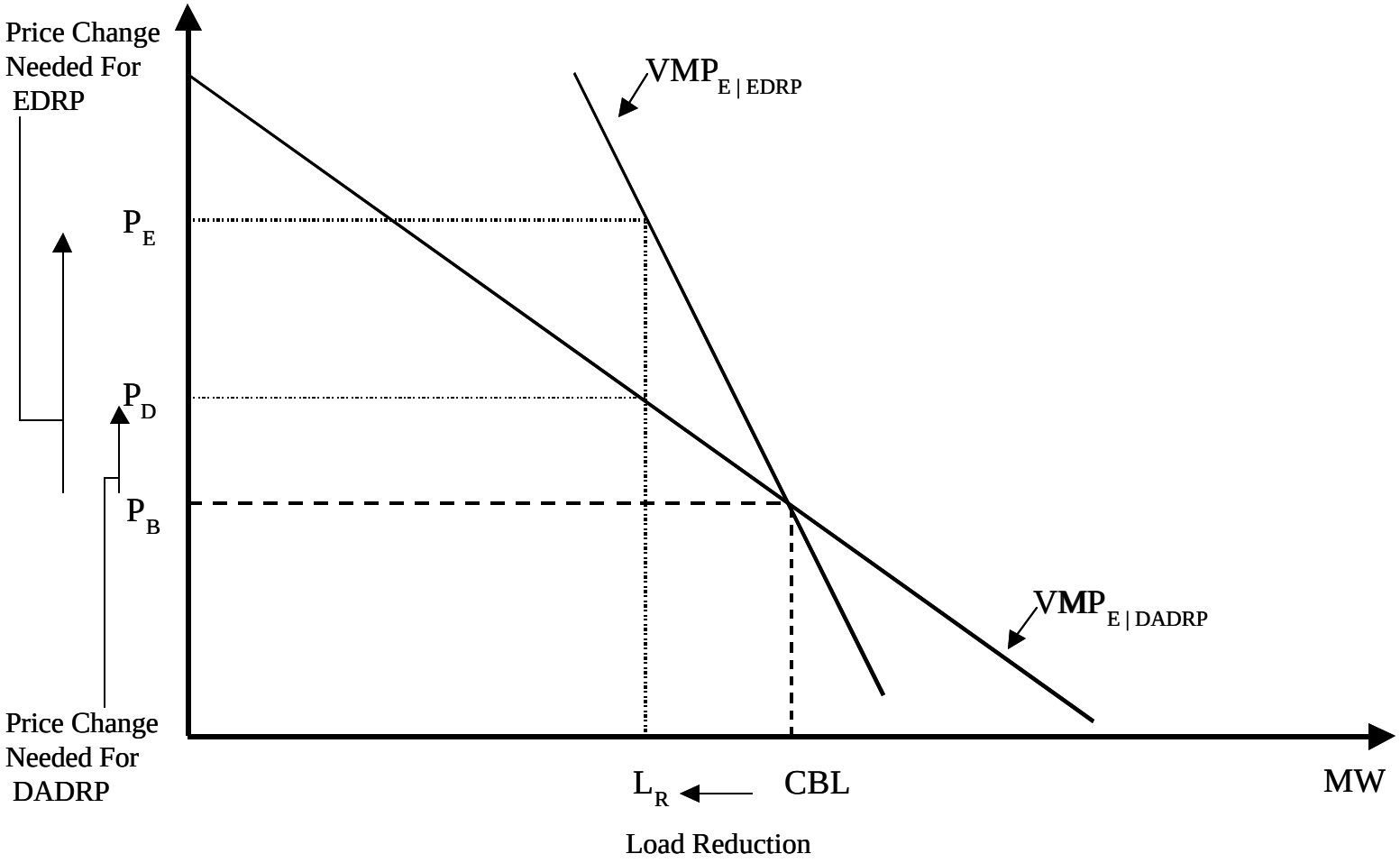


Fig. 5-2. Price Elasticities of Demand for Electricity: Equal Price Change

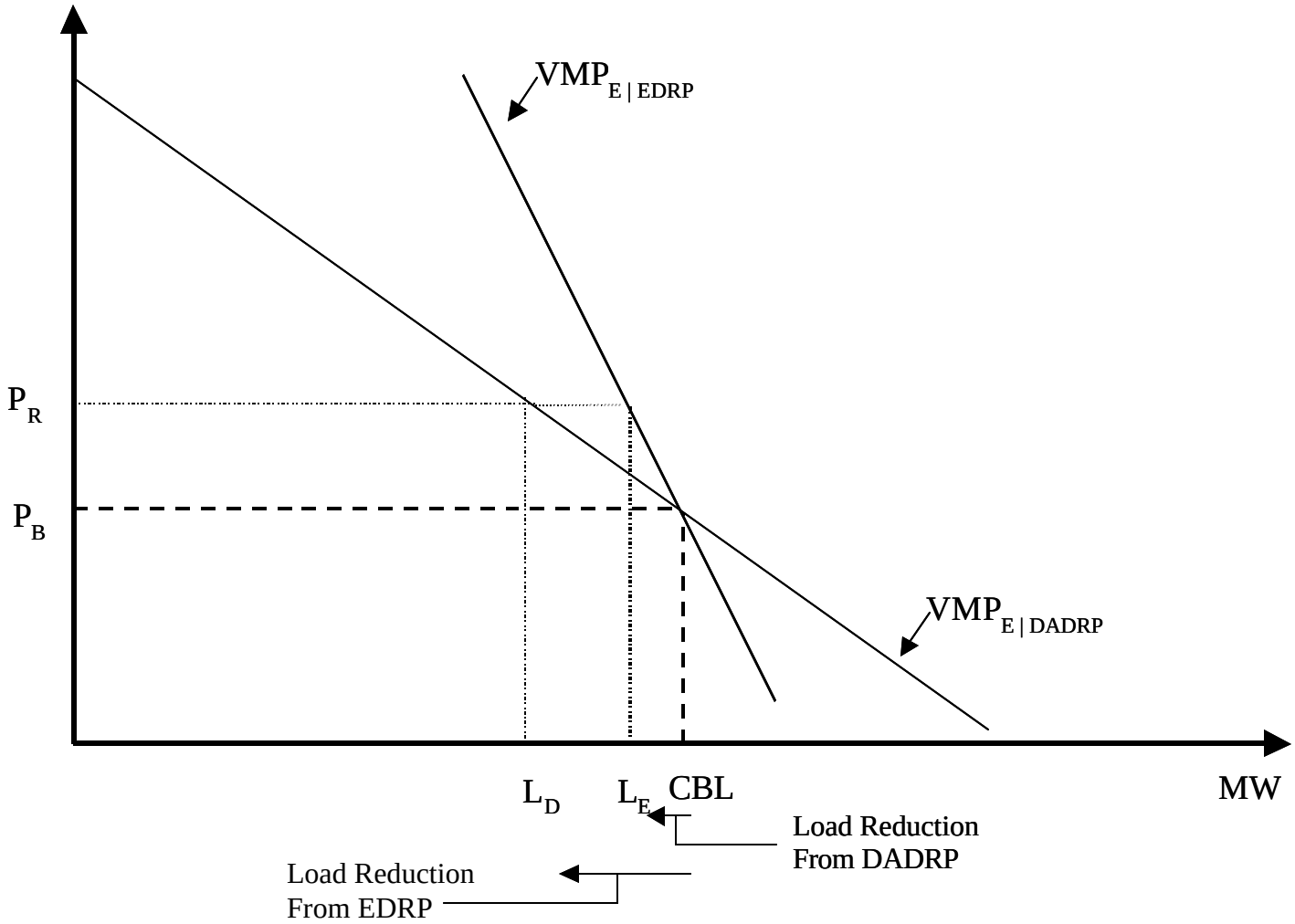


Fig. 5-3. Distribution of EDRP Customers by Elasticity of Demand for Electricity During Summer 2002 EDRP Events

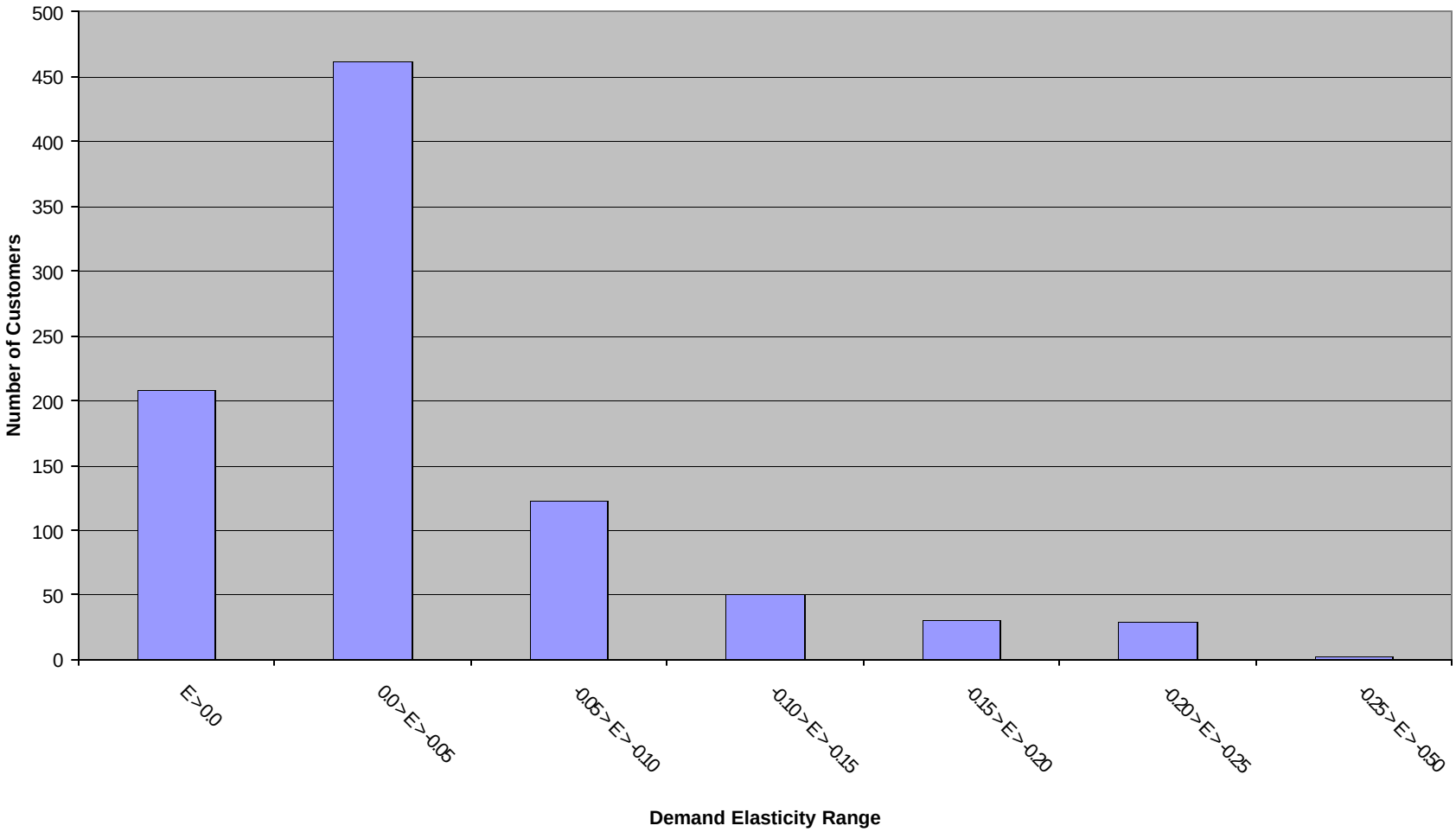


Fig. 5-4. Distribution of Elasticities by EDRP Participant's Electricity Consumption Level

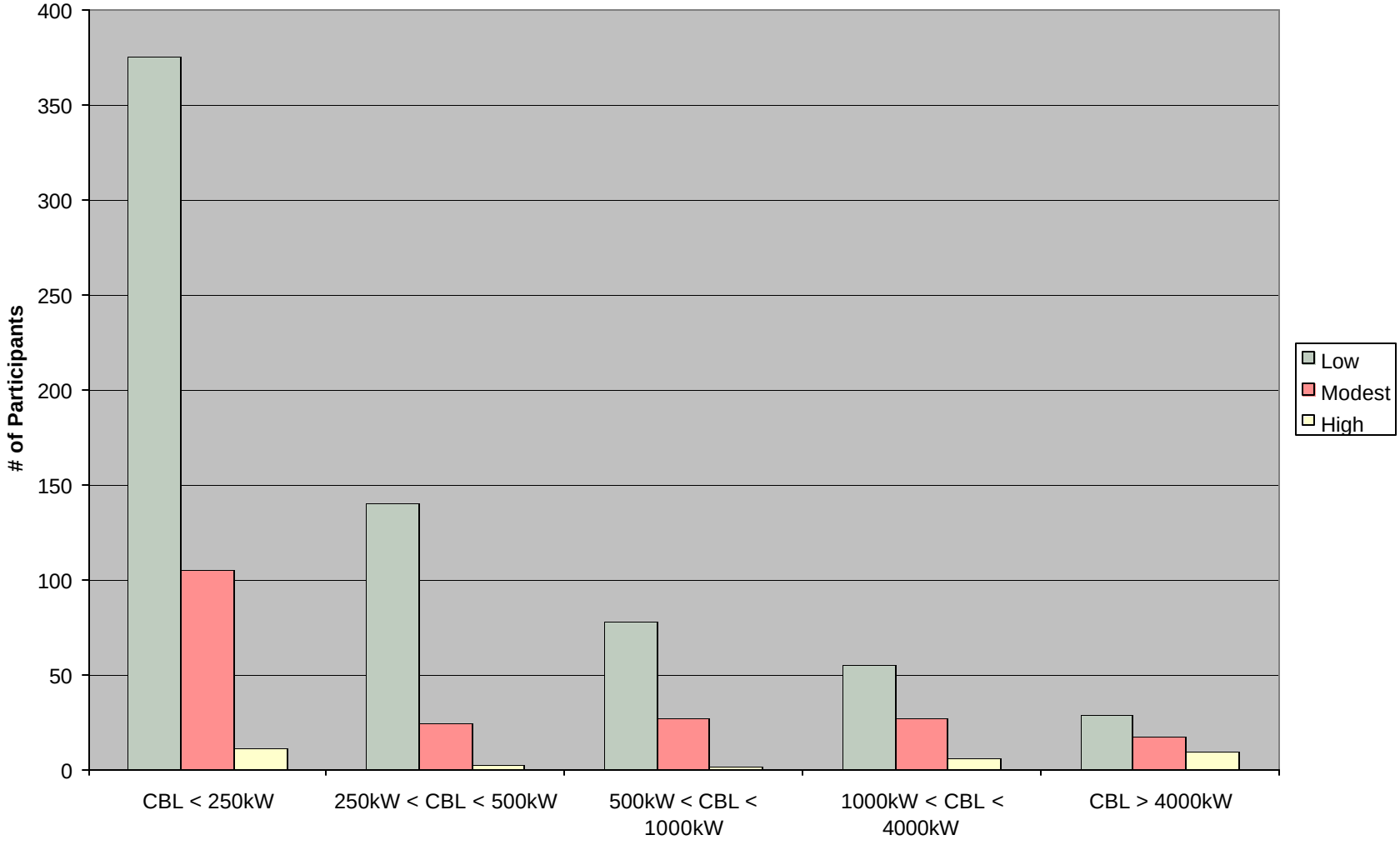


Fig. 5-5. NYISO-Wide 2002 EDRP Event Performance

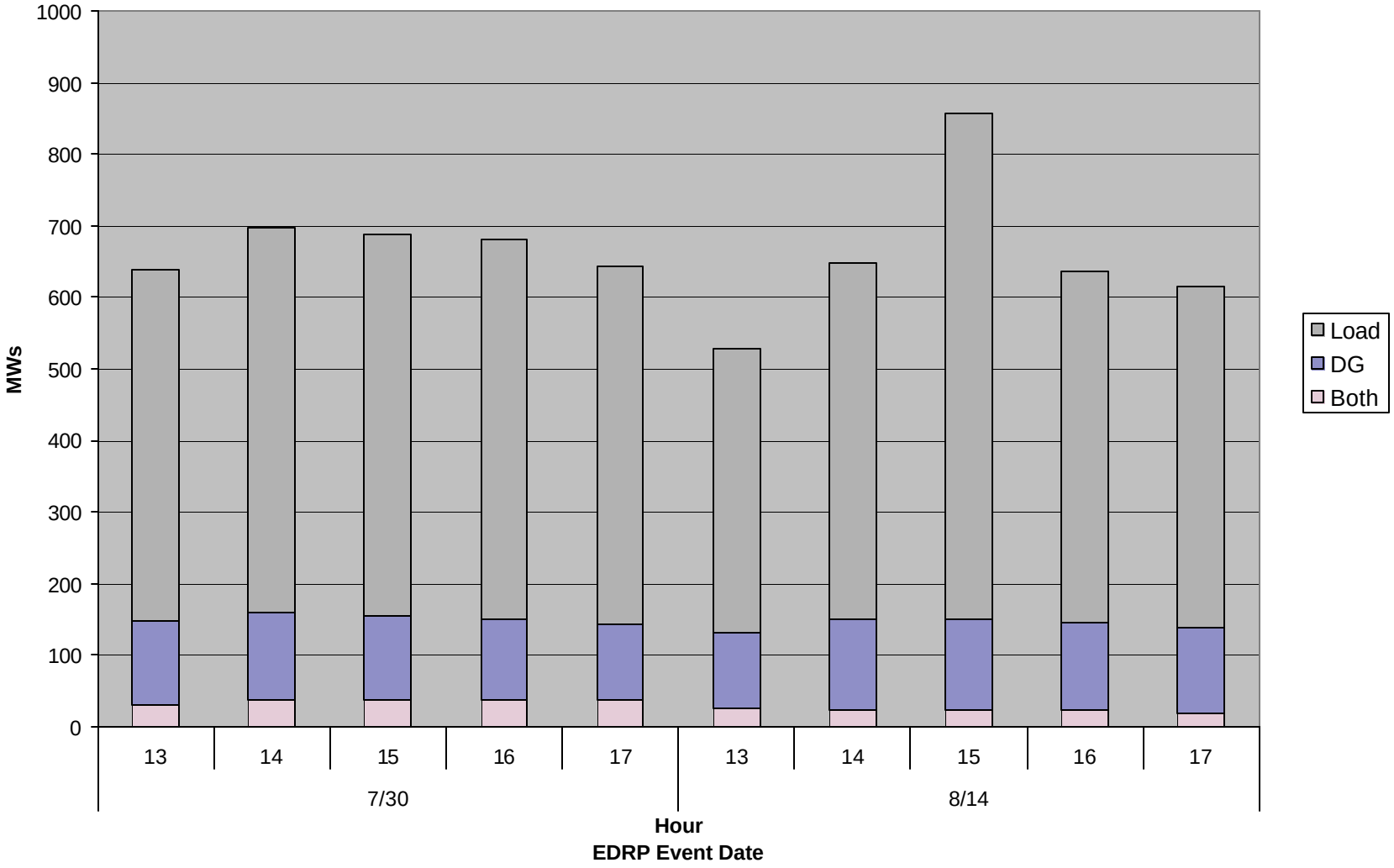


Fig. 5-6. Distribution of NYSERDA'S EDRP Customers by Elasticity of Demand for Electricity During Summer 2002 EDRP Events

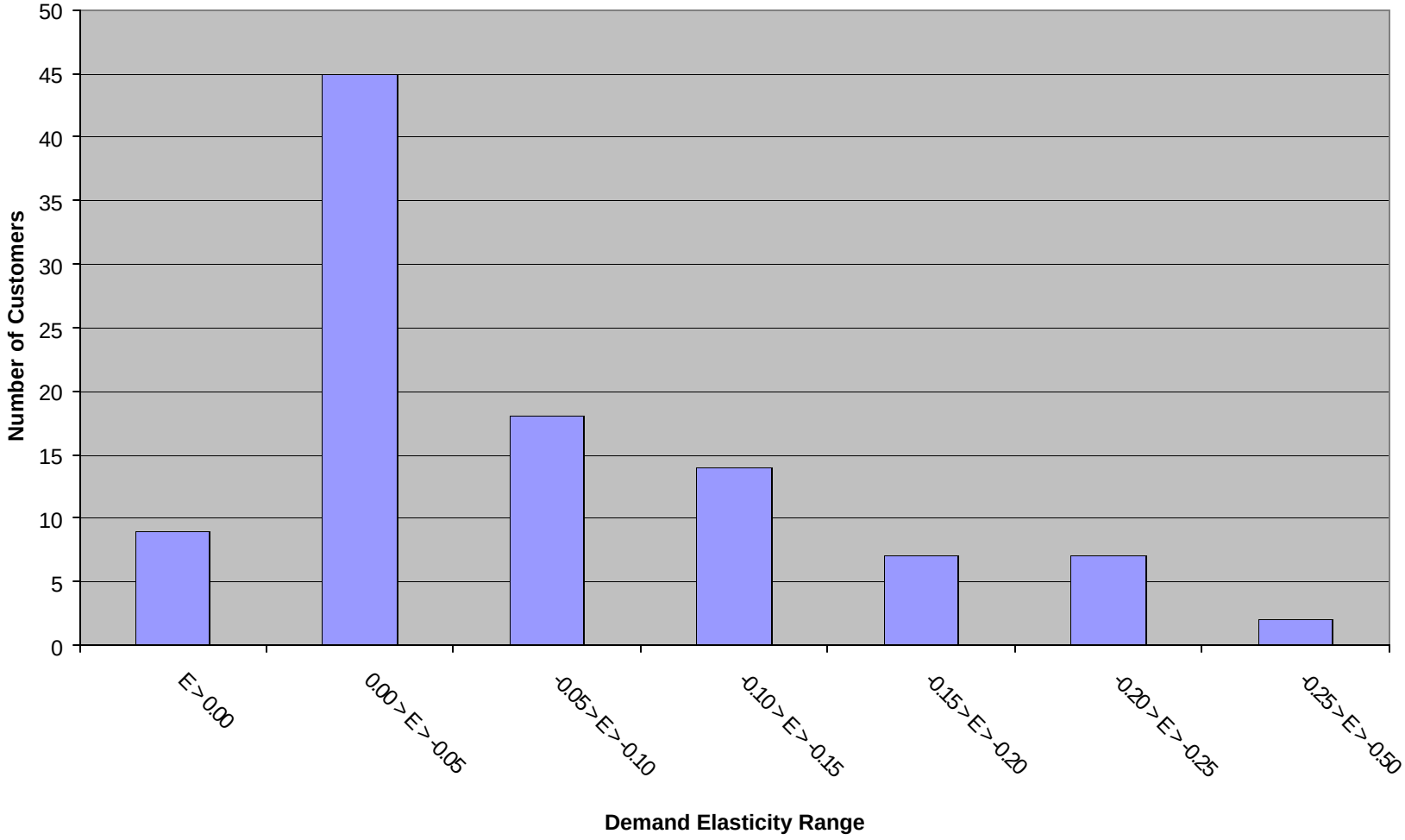


Fig. 5-7. Distribution of Non-NYSERDA EDRP Customers by Elasticity of Demand for Electricity During Summer 2002 EDRP Events

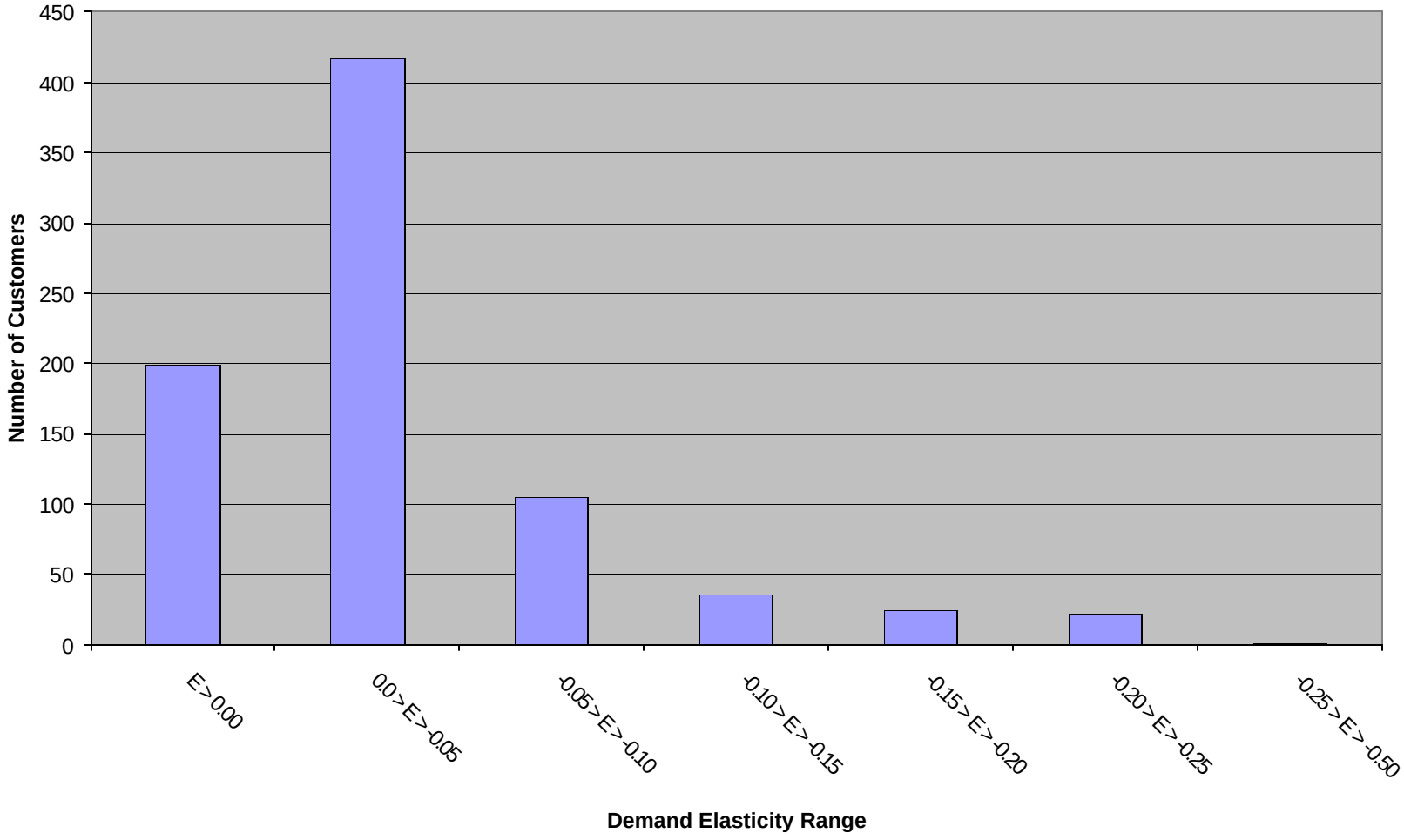


Fig. 5-8. Ratio of Average Hourly EDRP Performance to Initial Subscribed Load Reduction Capability by EDRP Event Day

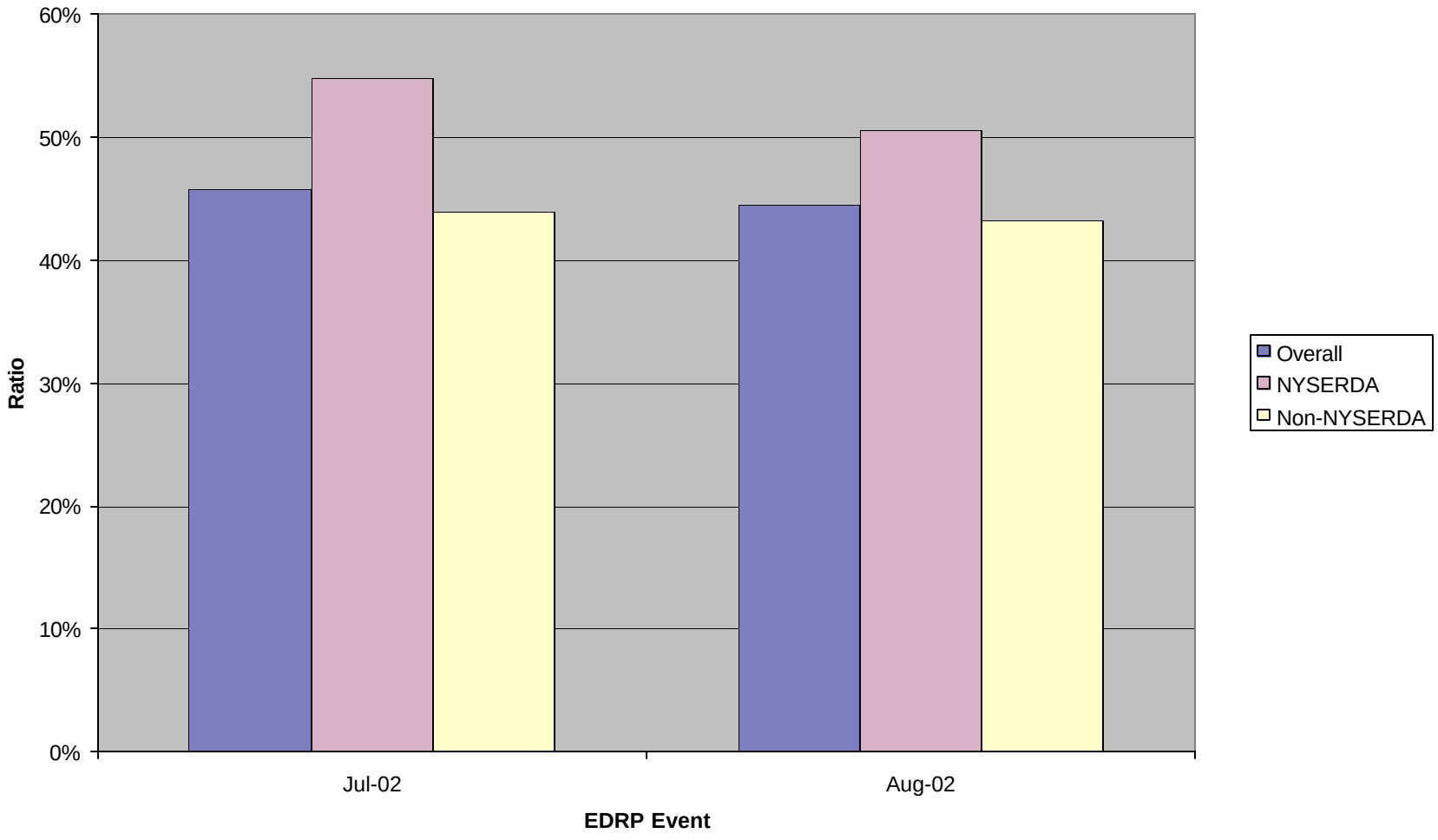


Fig. 5-9. Ratio of Average Hourly EDRP Load Curtailment Performance to Initial Subscribed Load Reduction Capability by Zone

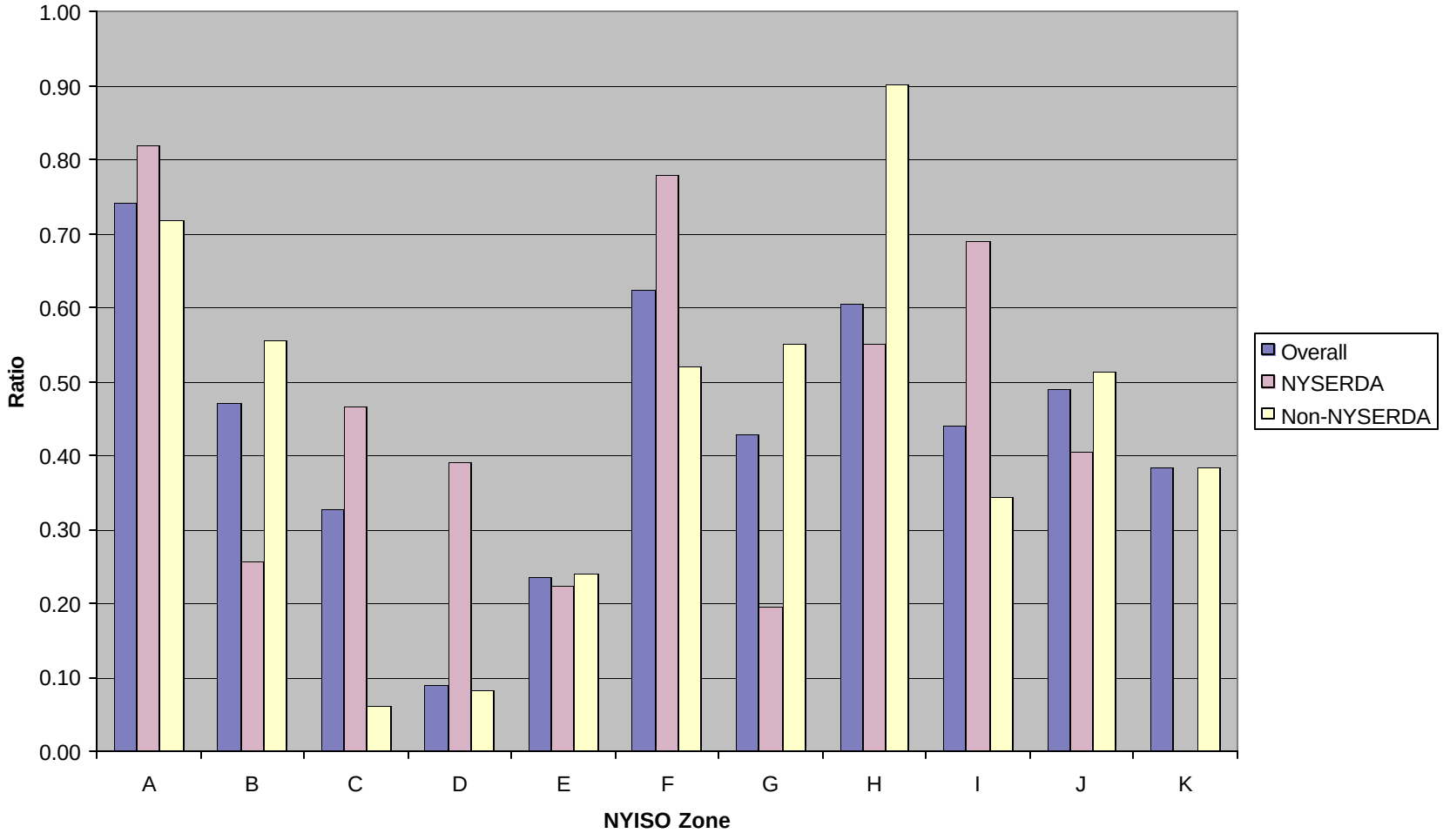


Fig. 5-10. SPI_c for NYSERDA and non-NYSERDA participants for EDRP Summer 2002 events

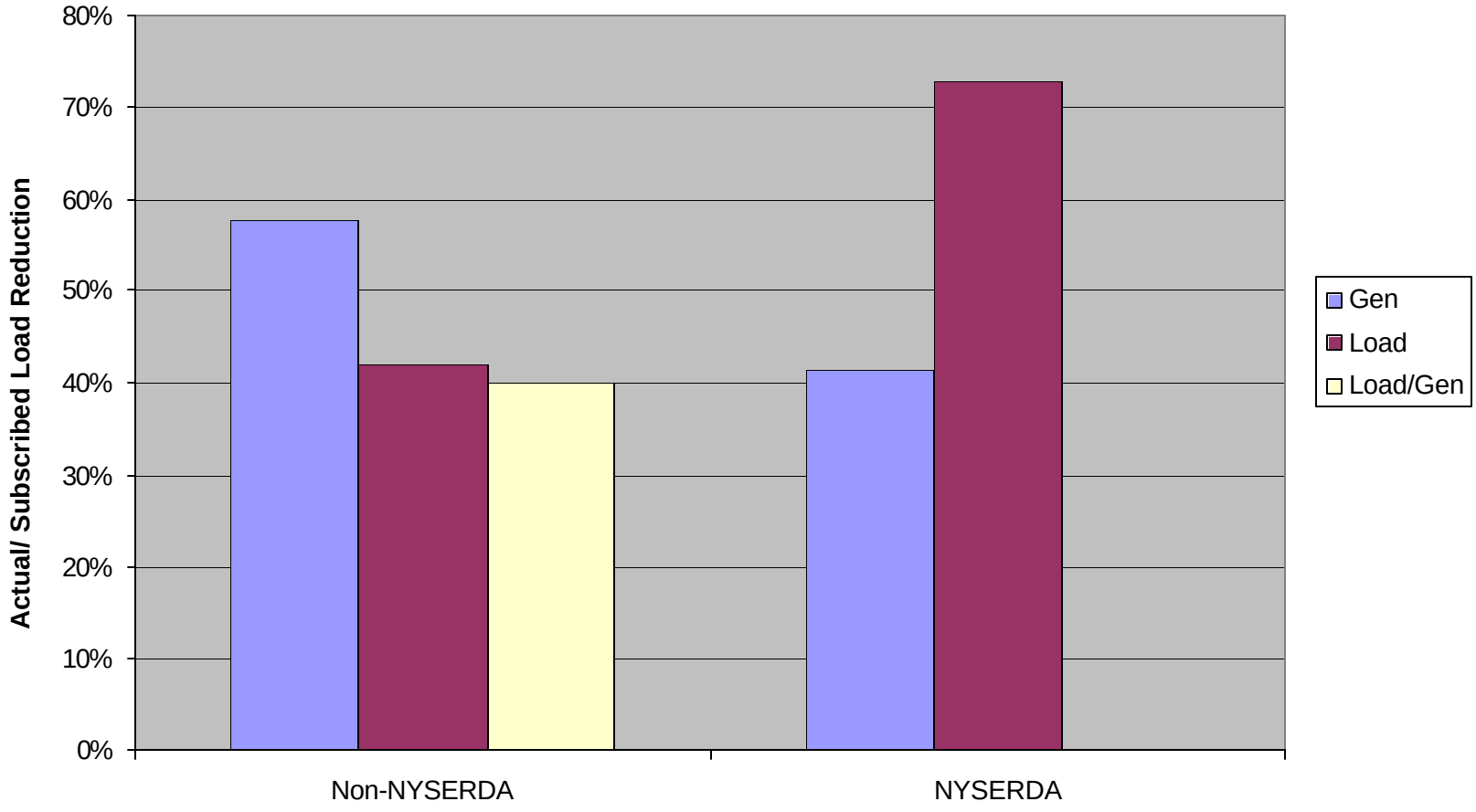
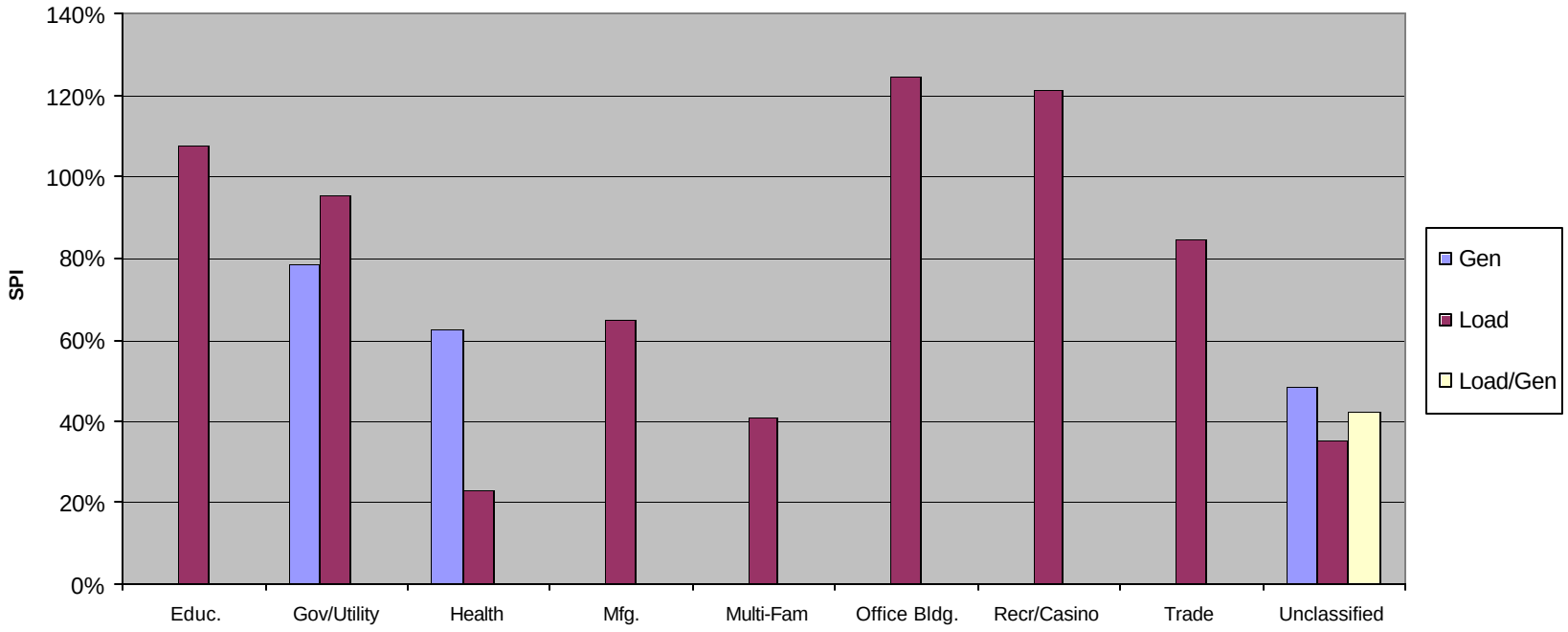


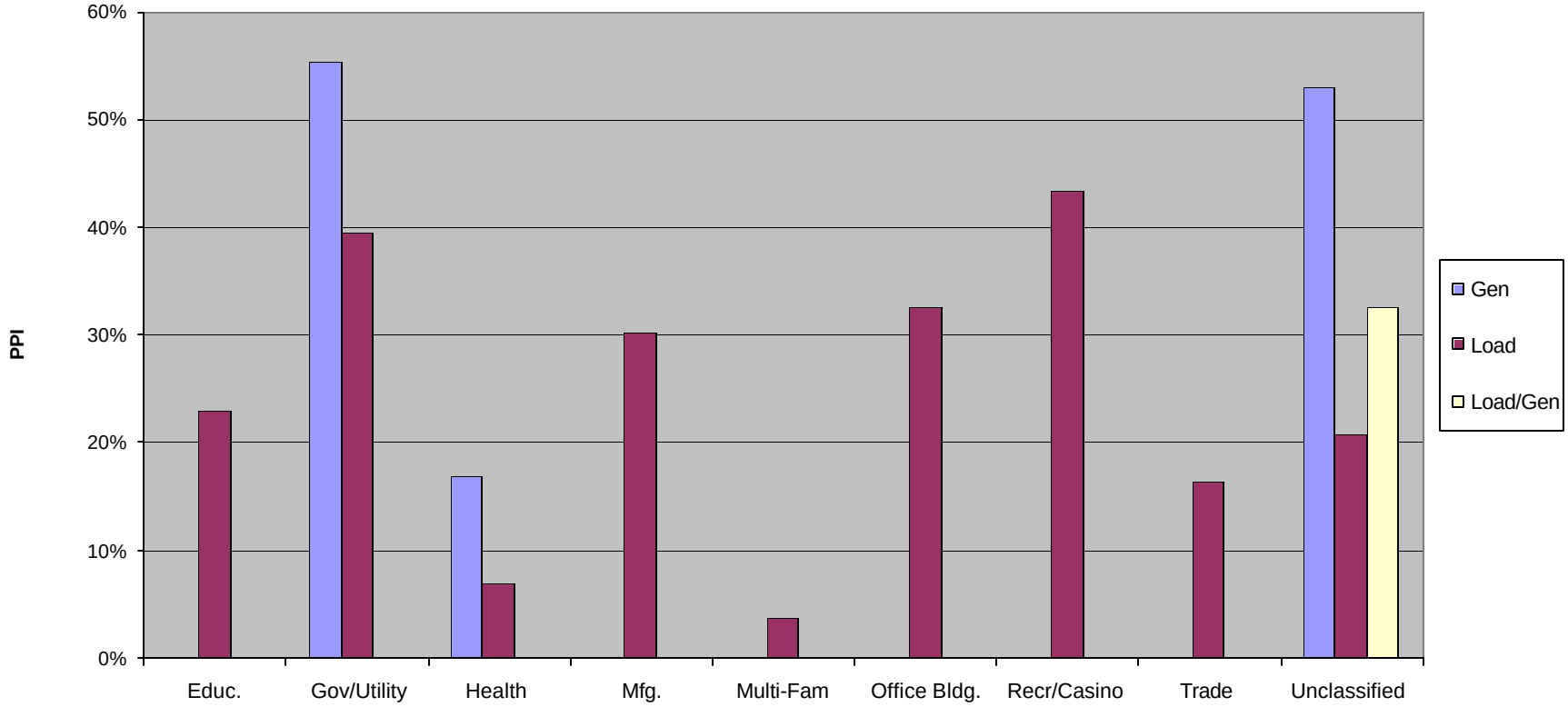
Fig. 5-11. SPI_c by Business Type and Load curtailment strategy for Summer 2002 EDRP events



	Educ.	Gov/Utility	Health	Mfg.	Multi-Fam	Office Bldg.	Recr/Casino	Trade	Unclassified
Subscribed MW of Active Participants	9	90	13	502	3	5	2	13	246
Subscribed MW of All Participants	30	123	28	558	9	8	5	26	551

The category "Unclassified" corresponds to SIC code 9900 and other non-classified aggregated load

Fig. 5-12. Peak Performance Index (PPI) by Business Type and Load Curtailment Strategy



	Educ.	Gov/Utility	Health	Mfg.	Multi-Fam	Office Bldg.	Recr/Casino	Trade	Unclassified
Subscribed MW of Active Participants	9	90	13	502	3	5	2	13	246

The category "Unclassified" corresponds to SIC code 9900 and other non-classified aggregated load

Fig. 5-13. Ratio of Actual Load Reduction to Subscribed Load Reduction by Program Participation

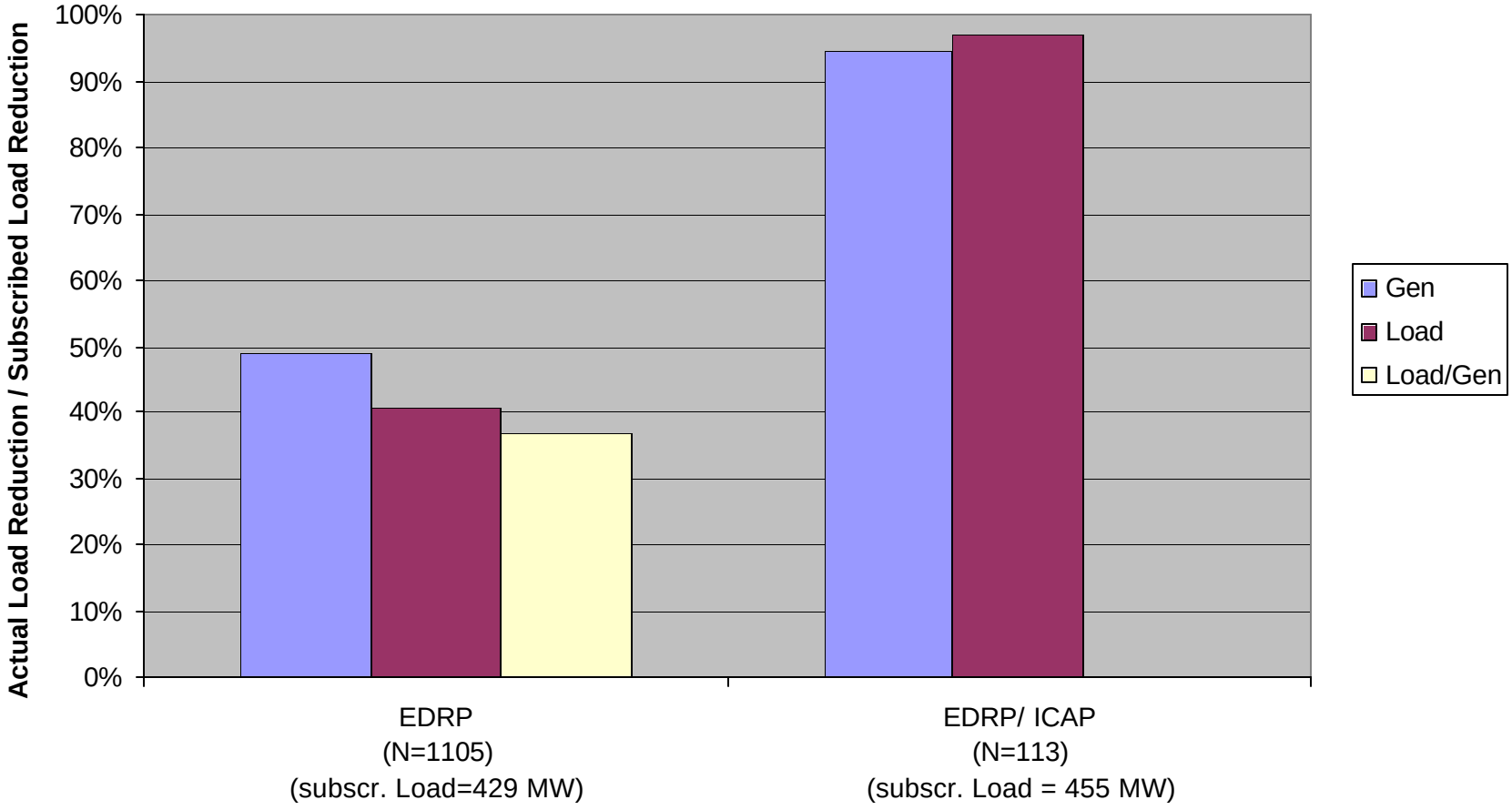


Fig. 5-14. EDRP Resources in Descending Order of Individual Subscribed Performance Index (SPI_c)

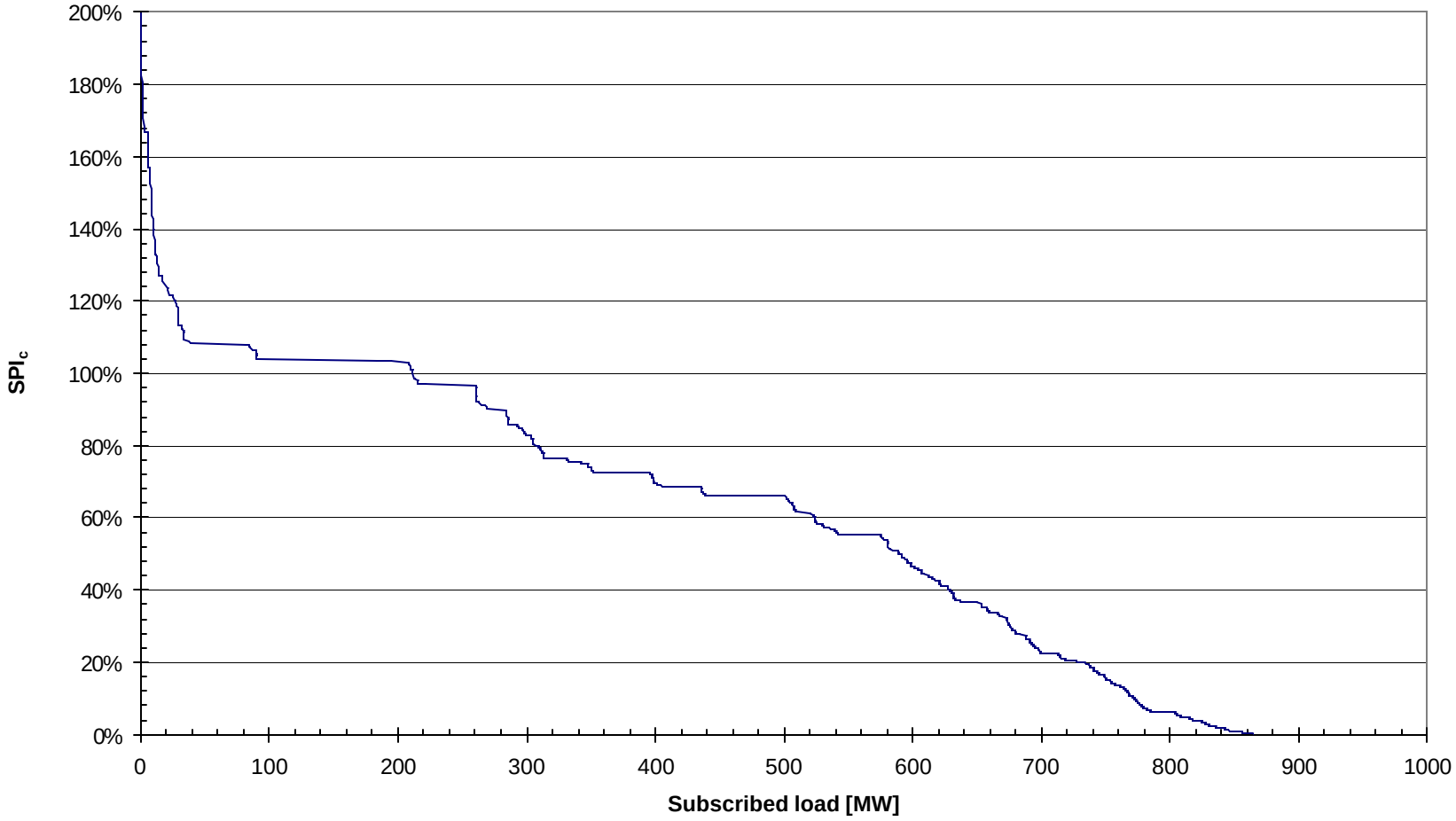
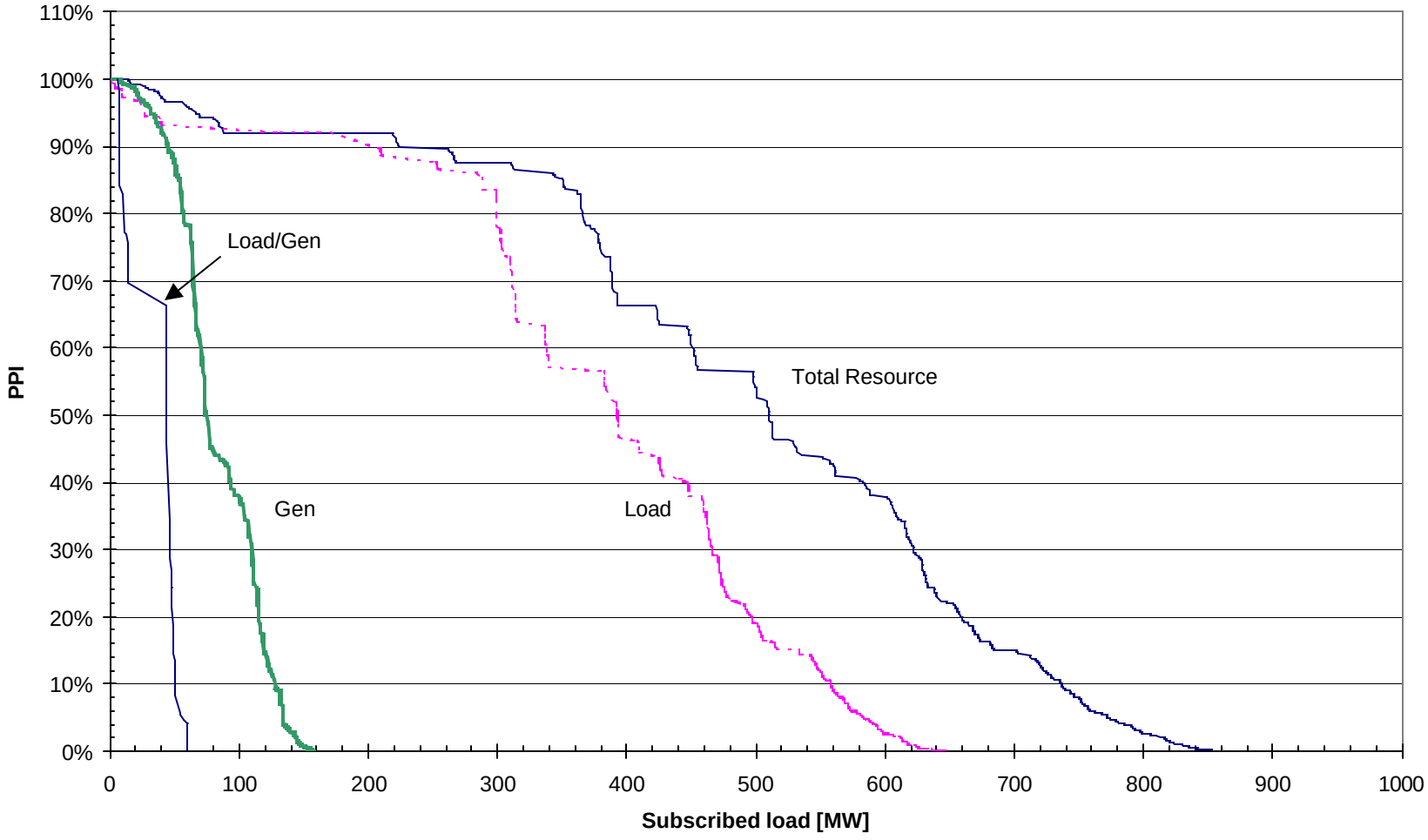


Fig. 5-15. EDRP Resources in Descending Order of Individual Peak Performance Index PPI



Chapter 6 - Assessing the Market Impacts of the NYISO's 2002 PRL Programs in New York's Day-Ahead and Real-Time Markets for Electricity

Introduction

This chapter documents and evaluates the performance of New York Independent System Operator's (NYISO) two price responsive load (PRL) programs in 2002. Ordinarily, one would expect EDRP events to be called during the hottest summer months. However, in addition to there being events called during July and August, there were also some unexpected EDRP events in April 2002. Rather than being needed to restore reserve margins during the periods of peak summer demand coincident with extreme weather conditions, EDRP load reductions were called in several zones in April due to some local conditions. Since it is expected that market conditions during the spring differ than during the summer months, it is appropriate to examine the April events independently from the summer events. More is said about this below, but at a minimum, it is important to base our estimates of the market effects on short-run supply curves for April, rather than supply curves representing the three summer months of June, July, and August.

In evaluating the EDRP events, the main focus is on the programs' benefits to system reliability, although they are also likely to have some effect on locational based marginal prices (LBMPs) in the real-time market, particularly in terms of mitigating extreme price spikes. In contrast, it is through the potential effectiveness in mitigating extreme price spikes that many believe bidding programs such as DADRP will bring additional "discipline" to the New York Electricity markets.

As part of this continuing evaluation of the performance of NYISO's price-responsive load (PRL) programs, it is, therefore, essential to understand how load bids accepted in DADRP or load offered in EDRP and SCR will affect locational based marginal prices (LBMPs) in both the day-ahead market (DAM) and the real-time market (RTM). Estimates of these price effects also help determine the over-arching, long-term value of PRL programs to customers, LSEs, and generators that comprise the NYISO membership. These effects have implications for market participation and for recruiting customers into the programs.

Because 2002 has already seen a substantial growth in EDRP enrollment and load subscription, it is also important to identify price reductions perhaps due to dispatching load reduction during EDRP events over and above that needed to reestablish system reserve margins. This situation could lead to excessive downward pressure on market prices and could have important implications for how much SCR and EDRP load is dispatched, of course within the context of what is feasible for system operators responsible for dispatch in real time.

We begin with some descriptive data that characterize the nature of load and LBMPs in the DAM and RTM in several of the major zones for which separate hourly prices are determined. Next, we provide a brief summary of the supply models described in greater detail by Neenan Associates (2002). As is seen in that report, a "spline" formulation, incorporating some variables that act to shifters, is needed to capture the "hockey stick" shape of the market supply curve. The price response to changes in load served is characterized in percentage terms by the price flexibility of supply: the percentage change in price due to a one percent change in load served. We re-estimate the supply models for the summer months of 2002. Further, we estimate separate models using April 2002 data, because the supply relationships during the spring probably differ from those in the summer months. Next, the data on the performance of customers in EDRP are presented and are used to estimate the effects of the program on electricity markets. This analysis is followed by a similar evaluation of DADRP. Finally, some conclusions and recommendation are presented.

Summary Data on Demand and LBMPs in the DAM and the RTM

To place the analysis into proper perspective, it is helpful to examine some summary statistics on hourly LBMPs and demand for the month of April, as well as for the three summer months of June, July, and August. We focus on the afternoon hours (1:00 pm through 7:00 pm) for two reasons. First, this is the period of the day during which demand across the State peaks; thus one would expect prices to be highest during the afternoon hours.[1] These circumstances would suggest that EDRP would be most likely be called during this time of the day. Second,

[1] As is seen in the report by Neenan Associates (2002) prices generally rise from early to mid-afternoon and then fall in each of the pricing zones. The same is true of load in both the day-ahead and real-time markets. There are isolated instances of high prices at other hours during the day, but they do not occur frequently enough to attempt modeling these morning hours along with the afternoon.

through careful examination of the data, the structure of the short-run supply relationship during this period is distinct from that during other times of the day.

In the discussion of the price data, and in the supply analysis below, the Capital zone is treated separately, as are the NYISO pricing zones for New York City and Long Island. [2] For both modeling and discussion purposes, the remaining eight zones are aggregated into two "super" zones. The three zones in the Hudson Valley between the Capital zone and New York City are combined into a single region (Hudson River "super" zone). The same is true for the five zones west of the total east transmission corridor (Western New York "super" zone).[3] By combining zones in which prices seem to be similar, we facilitate the analysis and improve the ability to estimate the short-run supply relationships. Fig. 6-1 contains the boundaries of these aggregate zones in relation to the boundaries of the 11 individual pricing zones.[4]

The Data for April 2002

Table 6-1 contains summary statistics on LBMPs in the DAM and RTM for April of 2002, as well as for fixed bid load in the DAM and actual load served in the RTM. [5] Because it is the NYISO's policy not to report load separately for New York City and Long Island, we aggregate those two zones for purposes of presenting summary data. However, separate supply models are estimated for New York and Long Island.

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[2] For this discussion, however, the NYISO has a policy not to report loads in the real-time or day-ahead markets separately for New York City or Long Island. Therefore, throughout this report loads in these two zones are either added together or are merely indexed in some fashion for reporting purposes to reflect loads relative to the mean or maximum load.

[3] To introduce some variety in presentation, the Hudson River "super" zone is sometimes referred to as the Hudson Region or Hudson River Zone, while the aggregate zone west of the total east transmission corridor is sometimes referred to as the Western "super" zone or just Western New York. Unless otherwise indicated, it is these aggregate zones that are being discussed. Further, in some cases, the term region is used interchangeably with zone.

[4] To create these "super" zones, loads for the individual component zones are simply added together. In contrast, LBMPs for these aggregate zones are calculated as load weighted averages of LBMPs for the individual component zones. This weighted averaging process is the logical way to calculate these aggregate zonal prices because the 11 individual zonal LBMPs are currently constructed as a load weighted average of the individual bus prices within a zone.

[5] Fixed bid load is the load bid into the DAM that the LSEs or other market participants want scheduled in the DAM regardless of the market-clearing price. It also includes load that is scheduled in the DAM, but is hedged under bilateral contract.

For the afternoon hours in April 2002, fixed bid load in the DAM averaged 14,724 MW statewide. In real-time, load served averaged 18,324 MW, nearly 20% higher than in the DAM. The difference between average load in the DAM and real time (52%) was most pronounced in the Hudson River super zone. In Western New York, the difference was only 17%, while in the downstate zones and in the Capital zone, average load in real time exceeded that scheduled in the DAM by about 25%.

In both real time and in the DAM, about 35% of the load was in Western New York, while about 46% was downstate, 7% was in the Capital zone and the remaining 10% to 11% was in the Hudson River super zone. Not surprisingly, the variability of load served in real-time was substantially higher than in the DAM in each zone. This difference in variability was most pronounced in the Hudson River super zone; the difference in variability in the downstate zones was also quite marked, while less so elsewhere in the state.

During the afternoon hours in April 2002, the prices both in the DAM and in real time were rather modest, on average. In the DAM, they averaged $49/MW downstate, and between $43/MW and $44/MW in the Hudson and Capital regions. They were substantially lower in Western New York, averaging about $32/MW. At no time did prices in any region exceed $200/MW, and they reached a low in Western New York of $19/MW.

The pattern was similar in the DAM, although downstate and in Hudson River regions prices in real time averaged between 5% and 7% higher than in the DAM, respectively. In the other two regions in Table 6-1, real time prices were averaged about 12% below those in the DAM. The variability of prices in real time was substantially higher than in the DAM. The downstate zones saw a small number of prices in excess of $300/MW, while the highest price in the Hudson super zone was just over $280/MW. In the Capital zone, the highest real time price in April 2002 was $121/MW. In the western super zone, real time prices never exceeded $88/MW, and they fell to as low as $5/MW.

The Data for the Summer of 2002

Table 6-2 contains summary statistics on LBMPs in the DAM and RTM for the three summer months of 2002, as well as for fixed bid load in the DAM and actual load served in the

RTM. [6] Because it is the NYISO's policy not to report load separately for New York City and Long Island, we report prices separately, but aggregate those two zones for purposes of presenting summary data. However, as in the case of the April evaluation, separate supply models are estimated for New York and Long Island.

For the afternoon hours of summer 2002, fixed bid load in the DAM averaged 19,006 MW statewide. In real-time, load served averaged 23,438 MW, nearly 23% higher than in the DAM (Table 6-2). The difference between average load in the DAM and real time (55%) was most pronounced in the Hudson River super zone. In Western New York, the difference was only 12%, while in the downstate zones and in the Capital zone average load in real time exceeded that scheduled in the DAM by about 13%.

Not surprisingly, the variability in load served in real time statewide (a standard deviation of 3,707) was substantially larger than the variability in fixed bid load in the DAM (a standard deviation of 2,619). This difference was even more pronounced for New York City and Long Island combined and in the Hudson region. However, in both the Capital zone and in Western New York, the variability in load in the two markets was nearly identical (Table 6-2).

Statewide, average summer prices for these afternoon hours were rather modest, but in the DAM and in real time (Table 6-2). The load weighted average prices statewide were $65/MW and $61/MW in the DAM and in the RTM, respectively. Downstate average prices were somewhat higher. In the DAM, prices averaged $87/MW on Long Island and $76/MW in the City. In real time, prices were somewhat lower, averaging $81/MW on Long Island and $71/MW in the City. For the Hudson River Region, average prices were $59/MW and $55/MW in the DAM and RTM, respectively, while in Western New York average prices were $47/MW in the DAM and only $44 in the RTM. Interestingly, average prices in the RTM were about 7% lower than in the DAM in all zones expect those in the Capital Zone. In that zone, average prices in the RTM were about 14% below those in the DAM ($49/MW in real time vs. $58/MW in the DAM).

The ranges and variability in prices in all regions were also higher in the RTM than in the DAM (Table 6-2). Prices in real time fell as low as $12/MW in Western New York and reached a high of $1,123/MW in New York City; maximum prices were very near or exceeded $1,000/MW

[6] Fixed bid load is the load bid into the DAM that the LSEs or other market participants what scheduled in the DAM regardless of the market-clearing price. It also includes load that is scheduled in the DAM, but is hedged under bilateral contract.

in all other zones as well ($996/MW, $1,008/MW, $1,106/MW, and $1,109/MW in Western New York, the Capital Zone, the Hudson River Region, and on Long Island, respectively). In the DAM, prices in the afternoon hours exceeded $200/MW only in the Capital Zone ($214/MW) and on Long Island ($600/MW). The variability of prices, as measured by the standard deviation, was over twice as large in real time ($69/MW) as it was in the DAM ($33/MW). The differences in price variability were similar in all other zones, except for Long Island, where the standard deviation in real time prices was only $7/MW higher in real time than in the DAM.

The Econometric Model of Supply

To assess the effects of EDRP and load reduction or on-site generation on the real-time electricity market in New York, we must quantify the change in price due to changes in the amount of PRL load bought or sold. This is the supply side of the market. A detailed discussion of the specification of the supply models is in Neenan Associates (2002), and only the highlights are repeated here.

In most research of this kind, the common strategy to identify the price response is to collect actual market price and quantity data, along with other relevant information affecting the supply/demand relationships, and then to estimate econometrically the supply and demand functions simultaneously using a variety of regression techniques. Economic theory provides the structural basis for selecting which influences to include (e.g., Chambers, 1988; Diewert, 1974; Preckel and Hertel, 1988; and Griffin, 1977). The form of the empirical econometric models also depends on the nature of the markets, but is influenced by pragmatic considerations such as data availability. In this application, the estimated coefficients on the variables in the models provide the basis for calculating price response to changes in demand, and since that is the primary objective of the evaluation of PRL programs, it is particularly important to have precise estimates for these coefficients.

The New York electricity market has been in operation for just over 3 years. For this analysis, we have access to the hourly price and load data for both the DAM and the RTM since the inception of market operations.[7] Our task is complicated by the fact that we are unable to employ data on generator bids or their bid curves. However, for the RTM, we do have access to

[7] Price data are publicly available on the NYISO web-site. Load data by zone are similarly available, but with a six-month lag. For this analysis, the NYISO made some still confidential load data available.

data on transmission constraints and net imports of electricity which proved to be essential in identifying the supply function in the RTM. More is said about the data below.

In determining the appropriate specification for the short-run supply functions in the RTM we had to pay particular attention to:

- the way in which equilibrium prices and quantities are determined; and
- a strategy for capturing the "hockey stick" shape of the supply function.

Each of these issues is discussed in turn below.

Equilibrium Price Determination

Tomek and Robinson (1981) demonstrate that the form of the econometric specification of supply models depends importantly on how the particular markets of interest function. Because of the unique nature of electricity as a commodity and the overriding need to maintain system reliability, wholesale prices for electricity in New York's two competitive markets, the DAM and the RTM, are determined "analytically" by the operation of the NYISO's SCUC and SCD scheduling and dispatch programs. This feature *clearly distinguishes* wholesale markets for electricity from those of other commodities. We know of no other markets that must function in this way. The implications for modeling the supply relationships are significant.

Although there are important differences in the structure and purposes for which SCUC and SCD models are used, LBMPs in the DAM and the RTM are determined as part of the solutions to these algorithms. Either in the day ahead or real time market, these algorithms use generators' bids and availability to minimize the cost of meeting, what is essentially for each hour, a fixed demand bid that LSEs have committed to purchase in the DAM at what ever prices clear the market. Thus, once the bids have been submitted in the DAM, or load is observed in real time, electricity demand is essentially exogenous to the system for purposes of determining LBMP by the scheduling and dispatch algorithms. For modeling purposes, the practical implication is that rather than estimating quantity-dependent supply functions as is done for many commodities, we must instead specify price-dependent supply functions.

Put differently, following the theoretical discussion of the short-run supply function in the DAM or the RTM (see Neenan Associates, 2000), it should be possible to identify the envelope supply curves by examining primarily bid load, actual load, and price data. As bid loads or actual loads differ by hour and day, the demand curves, which are essentially vertical, slide up

and down along a supply curve. The observations on bid load, actual load, and prices thus effectively trace out a number of supply curves in the DAM and the RTM. In these specifications, price is the dependent variable in the regressions and bid loads, or load served in real time are the independent variables.[8]

If there were no shifts in supply due to different generator availability or general level of prices bid, there would be no need for generator bid data to identify the supply response flexibilities. However, these factors, and others, such as loads in adjacent regions and hours of the day, are extremely important as well. For these reasons, our econometric specification is zonal specific and includes explanatory variables other than load.

Further, the general underlying nature of these short-run supply functions is captured by the stylistic "hockey stick" shape—being relatively flat at low and moderate loads, but then rising sharply as load nears system capacity (e.g., Fig. 6-2). It is as though the curves had separate regimes (Fig. 6-3 and 6-4). These regimes were captured as piece-wise "spline" functions with different intercepts between the regimes (Neenan Associates, 2002). The points in Fig. 6-5 with high loads and low prices seem at odds with the general nature of supply. We capture these effects by including variables, such as measures of congestion, that shift the slope of the supply curve. These shifts are illustrated in Fig. 6-6. The supply flexibilities, defined as the percentage

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[8] Estimating these electricity supply relationships is nearly identical to the pseudo-data methods developed by Griffin (1977) and Preckel and Hertel (1988) to generate summary, smooth cost and output supply response relations based on many repeated solutions to linear programming (LP) models. Griffin, for example, used pseudo-data arising from LP solutions to estimate a summary electricity cost function for later incorporation into the Wharton econometric model. In Preckel and Hertel's application, a complete system of output supply and input demand functions for agricultural commodities and inputs was estimated. The observations on quantities were the optimal output levels of several products determined by the successive solutions to the programming model. The prices were those assumed for each of the corresponding programming solutions. To map out the entire supply surface, the authors developed a complex sampling design to generate a wide range of relative input and output price differentials. In turn, these simulated data were used to estimate econometrically a smooth supply and input demand surface assuming a translog flexible functional form.

Viewed from a very practical perspective, this pseudo-data exercise is strictly a convenient way to summarize the relationships between the input data and the solutions to complex programming models. This is accomplished by regressing the solutions of the programming models on the input data to the programming models themselves. In a very real sense, the LBMPs from the DAM and the RTM are generated in exactly the same way as the data used in these "pseudo-data" exercises. The major difference is that the supply and demand quantities are used as input data in the SCUC and SCD models, and it is the prices that are determined by the solution to the model. Because of the way in which the data are generated, we identify the price-dependent supply curve.

change in price due to a percentage change in load, are used to estimate the change in prices due to a change in load.

The "Spline" Formulation of the Supply Curve

To capture the "hockey stick" nature of electricity supply, it is necessary to use a "spline" formulation of supply in which we identify points (often called knots) at which the supply relationship changes its structure. For our purposes, these "knots" are defined to isolate the ranges in load for which the supply envelope is functionally different. We hypothesize that three regimes should be sufficient, and as is seen in Neenan Associates (2002), there are cases in which two regimes are sufficient. Assuming a log-linear specification, we begin by defining three zero-one variables, one for each segment of load (e.g., fixed bid load or actual load depending on which market is being estimated) measured in logarithmic terms (lnL):

(1) $D_1 = 1$ if $\ln L \leq \ln L_1^*$, otherwise $D_1 = 0$;

(2) $D_2 = 1$ if $\ln L_1^* < \ln L \leq \ln L_2^*$, otherwise $D_2 = 0$;

(3) $D_3 = 1$ if $\ln L > \ln L_2^*$, otherwise $D_3 = 0$.

where, L = fixed bid load or real time load and the subscripts indicate specific MW loads.

The Linear "Spline" Function

Now, for a linear "spline" specification, the inverse supply relation is given by:[9]

(4) $\ln LBMP = \alpha_1 D_1 + \alpha_2 D_2 + \alpha_3 D_3 + \beta_1 D_1 \ln L + \beta_2 D_2 \ln L + \beta_3 D_3 \ln L$.

This specification is a simple dummy variable regression. But in its unconstrained form, there is no guarantee that the value of the fitted function coming into a "knot" is equal to the value of the function coming out of the "knot". We impose constraints to ensure that this requirement is met for internal consistency of the piece-wise function. Thus, to rule out jumps in the fitted values of the dependent variable, we must constrain the function (4) in the following way (Ando, 1997 and Neenan Associates, 2002):

(5) $\alpha_1 + \beta_1 \ln L_1^* = \alpha_2 + \beta_2 \ln L_1^*$ or $\alpha_1 = -\beta_1 \ln L_1^* + \alpha_2 + \beta_2 \ln L_1^*$.

(6) $\alpha_2 + \beta_2 \ln L_2^* = \alpha_3 + \beta_3 \ln L_2^*$ or $\alpha_3 = - \beta_3 \ln L_2^* + \alpha_2 + \beta_2 \ln L_2^*$.

The resulting constrained regression (equation (4) subject to equations (5) and (6)) can be estimated by ordinary least squares (OLS), through simple variable transformations made possible by solving equations (5) and (6) for α_1 and α_3, and then substituting the results into equation (4). In this way, we eliminate all of the intercept terms except α_2, and we are left with the following specification:

(7) $\ln LBMP = \alpha_2 \{ D_1 + D_2 + D_3\} + \beta_1 \{ D_1 [\ln L - \ln L_1^*]\}$

$+ \beta_2 \{ D_1 \ln L_1^* + D_2 \ln L + D_3 \ln L_2^*\}$

$+ \beta_3 \{ D_3 [\ln L - \ln L_2^*]\}$.

In the data, the three zero-one variables add to a vector of ones. Thus, the first term in equation (7) reduces to a standard intercept term in OLS. All parameters of the original model are identified from this regression, except for α_1 and α_3. These parameters are identified after the fact by using equations (5) and (6).

Once equation (7) is estimated and the remaining parameters are identified, we can use equation (4) to calculate the supply price flexibilities. These flexibilities will differ in each regime of the spline function. That is, the partial logarithmic derivatives of equation (7) with respect to the logarithm of L are:

(8) $\partial \ln LBMP / \partial \ln L = \beta_1$, if $\ln L \leq \ln L_1^*$;

(9) $\partial \ln LBMP / \partial \ln L = \beta_2$, if $\ln L_1^* < \ln L \leq \ln L_2^*$;

(10) $\partial \ln LBMP / \partial \ln L = \beta_3$, if $\ln L > \ln L_2^*$.

Thus, while these supply price flexibilities are constant over the corresponding ranges in load defined by the knots, this model allows them to differ across the intervals. Our principle hypothesis is that the price flexibilities will be positive and will rise as load rises—that is $\beta_1 < \beta_2 < \beta_3$. We constrain the calculated value of lnLBMP at the three "knots" to be equal in approaching the "knot" from either direction; it is these constraints that allow the flexibilities to

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[9] For computational convenience and additional flexibility in the model, this function is actually specified to be linear in logarithms. The subscripts for zone and time of day have been suppressed for notational simplicity.

differ. From equation (5) we see that $\beta_1 < \beta_2$, as long as $\alpha_1 > \alpha_2$. Likewise, $\beta_2 < \beta_3$ as long as $\alpha_2 > \alpha_3$.

A More Complex "Spline" Formulation

This linear "spline" formulation adds tremendous flexibility to the supply model, but it still requires that the price flexibility is constant within a particular interval of L. To relax this restriction, we need only make this formulation non-linear in the logarithm of L. Further, if there are other factors that affect supply, we can capture them by incorporating variables that shift the supply curve. Each of these refinements in the model is discussed in detail in Neenan Associates (2002), but they can be summarized in the following way. The model now includes a variable X that shifts all segments of the function in the same fashion and an interaction term, X lnL (e.g, X multiplied by lnL), whose slope differs between the "knots".[10] The "spline" equation becomes:[11]

$$(11)\quad \ln LBMP = a_1D_1 + b_1D_1X + c_1D_1 \ln L + d_1D_1 X \ln L$$
$$+ a_2D_2 + b_2D_2X + c_2D_2 \ln L + d_2D_2 X \ln L$$
$$+ a_3D_3 + b_3D_3X + c_3D_3 \ln L + d_3D_3 X \ln L$$

The constraints to assure that the function has the same value coming into and going out of the knots are given by:

$$(12)\quad a_1 + b_1X + c_1 \ln L_1^* + d_1X \ln L_1^* = a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^*$$

$$(13)\quad a_3 + b_3X + c_3 \ln L_2^* + d_3X \ln L_2^* = a_2 + b_2X + c_2 \ln L_2^* + d_2X \ln L_2^* .$$

By placing these constraints on the function at these "knots", we force the values of lnLBMP to be equal regardless of the direction from which we approach the "knot" without the corresponding parameters all being equal to one another. Suppose, for example, that we want the marginal effect of a change in lnL on lnLBMP to be higher for values of lnL across successive knots. A sufficient, but certainly not a necessary condition, for this to happen is for $c_3 > c_2 > c_1$; d_3

[10] By allowing for interactions between the variable over which the "spline" is defined and other continuous or discrete variables, not only can we accommodate factors that shift supply for a given quantity, but we can also accommodate a specification that is non-linear in the logarithm of load by setting the shifter variable equal to the logarithm of load.

[11] When X = lnL, the model becomes quadratic in lnL.

$> d_2 > d_1$; and $a_1 > a_2 > a_3$. If this were merely a linear "spline" function in lnL, the b's, and d's would all be zero, and the sufficient condition above would involve only the c's and the a's.

To estimate this model using OLS, we must again solve the two equations above for a_1 and a_3:

(14) $a_1 = a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^* - [b_1X + c_1 \ln L_1^* + d_1X \ln L_1^*]$; and

(15) $a_3 = a_2 + b_2X + c_2 \ln L_2^* + d_2 \ln L_2X^* - [b_3X + c_3 \ln L_2^* + d_3X \ln L_2^*]$.

Substituting these expressions into equation (11), we have;

(16) $\ln LBMP = D_1 \{a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^* - [b_1X + c_1 \ln L_1^* + d_1X \ln L_1^*]\}+$

$b_1D_1X + c_1D_1 \ln L + d_1XD_1 \ln L + a_2D_2 + b_2D_2X + c_2D_2 \ln L + d_2D_2X \ln L$

$+ D_3 \{ a_2 + b_2X + c_2 \ln L_2^* + d_2X \ln L_2^* - [b_3X + c_3 \ln L_2^* + d_3X \ln L_2^*]\}+ b_3D_3X +$

$c_3D_3 \ln L + d_3D_3X \ln L$.

Combining those terms for which there is a common parameter, we have:

(17) $\ln LBMP = a_2 [D_1+ D_2+ D_3]+b_1 [D_1 X–D_1X]+b_2 [D_1X+ D_2X+D_3X]+b_3 [D_3X-D_3X]$

$+ c_1 [D_1 \ln L – D_1 \ln L_1^*] + c_2 [D_1 \ln L_1^* + D_2 \ln L + D_3 \ln L_2^*]$

$+ c_3 [D_3 \ln L – D_3 \ln L_2^*] + d_1 [D_1X \ln L – D_1X \ln L_1^*]$

$+ d_2 [D_1X \ln L_1^* + D_2X \ln L + D_3X \ln L_2^*] + d_3 [D_3 \ln L – D_3 \ln L_2^*]$

Again, since the sum of the zero-one variables, $[D_1+ D_2+ D_3]$ is unity, and the terms associated with b_1 and b_3 are zero, a_2 becomes an intercept term, and X, the variable that shifts the function in the same way across "knots", becomes a standard level term in the regression. This means that a_2, the intercept for the second segment, is identified directly in the regression along with the other coefficients, but a_1 and a_3 must be evaluated using equations (14) and (15). We cannot identify b_1 and b_3, but that is as it should be because we have assumed that X shifts the function identically regardless of the value of lnL, and this shift is captured by b_2. This is not true for the slope of the function, because of the interaction between X and lnL.

The marginal effects of the independent variables on the value of lnLBMP are of most interest in this model. That is, we want to identify from equation (11) the marginal effects of lnL and X on lnLBMP. Taking the partial derivatives of lnLBMP with respect to lnL for the three segments, we have:

(18) $\partial \ln LBMP / \partial \ln L = c_1 + [d_1 X]$, if $\ln L \leq \ln L_1^*$;

(19) $\partial \ln LBMP / \partial \ln L = c_2 + [d_2 X]$, if $\ln L_1^* < \ln L \leq \ln L_2^*$;

(20) $\partial \ln LBMP / \partial \ln L = c_3 + [d_3 X]$, if $\ln L > \ln L_2^*$.

These marginal effects differ by segment and are now functions of X. The marginal effects of X on lnLBMP would be equal to b_2 for all values of lnL if it were not for the interaction terms between X and lnL. Because of the interaction, the partial derivatives of lnLBMP with respect to X are:

(21) $\partial \ln LBMP / \partial X = b_2 + d_1[\ln L]$, if $\ln L \leq \ln L_1^*$;

(22) $\partial \ln LBMP / \partial X = b_2 + d_2 [\ln L]$, if $\ln L_1^* < \ln L \leq \ln L_2^*$;

(23) $\partial \ln LBMP / \partial X = b_2 + d_3 [\ln L]$, if $\ln L > \ln L_2^*$.

These effects now differ by segment, and they are functions of lnL.

Estimates of the Short-Run Electricity Supply Curves

This section contains a discussion of the estimated short-run electricity supply curves for the three NYISO pricing zones and the two "super" zones developed above. We begin with estimates of the real-time supply curves for the Hudson "super" zone and for New York City and Long Island for April 2002. These are the results needed to simulate the effects in the real-time market of the April 2002 EDRP emergency events. These supply relationships are in Tables 6-3 through 6-5. The supply models needed to simulate the market effects of the summer 2002 EDRP events are reported in Tables 6-6 through 6-10. Finally, the summer 2002 supply models for the DAM are needed to assess the performance of DADRP, and they are reported in Tables 6-11 through 6-15.

In each table, the estimated coefficients for the explanatory variables are reported, along with the t-ratios.[12] For the most part, the supply models are specified entirely in logarithmic form

[12] As a result of the different regimes in each supply function, there is reason to believe that the model's error terms are not constant across observations. If this is true, the assumptions of the ordinary regression model are violated, and the OLS estimators remain unbiased, but they are no longer consistent (e.g. no longer the minimum variance estimators). The practical implication is that the standard errors could be over- or underestimated—thus affecting the level of significance associated with the t-statistics (Gujarati, 1995).

so that the supply flexibilities are calculated according to equations (18-20). In the cases where there are no interaction terms with load, or if load squared is not in the model, then the supply price flexibilities will be constant, as they are in conditions (8-10).[13]

Before discussing the specific results in detail, some general comments are in order. Overall, the performance of the supply models is quite remarkable. In all cases over half the variation in the dependent variable is explained. One could hardly hope for any better results, given the substantial variation in LBMP at high load levels and the availability of only a small number of other variables for use as shifters in the models to capture the effects of factors other than load that affect LBMP. The figures in Appendix A contain graphs of the estimated supply functions over-laid on a scatter of the actual load and LBMP data for each zone, market, and time period. The supply functions were estimated and plotted for the minimum, maximum, and average levels of the appropriate "shifter" variables. In so doing, we demonstrate the importance

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It is advisable to test for the existence of heteroscedasticity (the error terms are correlated with load), but this was problematic given the need to transform the variables for the "spline" formulation. General tests of heteroscedasticity, such as the White test which regresses the estimated squared error on a quadratic expression in all the explanatory variables, led to estimates of the variance-covariance matrix that were not of full rank. This was most likely due to the transformation of the variables needed to estimate the "spline" function. Thus, these tests were of little use.

Since load varies systematically over the afternoon hours, we also tested for auto-correlation in the error terms. If autocorrelation in present, then the error in the current hour is related to those in one or more previous hours, and again the OLS estimators remain unbiased, but are inconsistent. The test for autocorrelation is to regress the estimated squared error from the OLS regression in time t on the estimated errors in times t-1, ..., (t-k). To conduct these tests, it was necessary to assume that the same auto-regressive error structure exists from the evening of one day to the afternoon of the next as it does from hour to hour. There is no good way to test the validity of this assumption, but a similar assumption is often implicitly necessary in other electricity demand and supply studies when weekends are treated differently from weekdays. If the tests suggest autocorrelation is present, the model is essentially re-estimated using maximum likelihood (ML) methods. This procedure generates the appropriately estimated variance-covariance matrix from which to calculate the standard errors of the coefficients and the t-ratios. The tests for autocorrelation and the corrected estimates of the models were performed using PROC AUTOREG in SAS.

[13] There are a couple of variables, such as the number of minutes during which constraints are binding in a given hour, in which there are legitimately many zero observations. These variables could not be transformed into logarithms, and are entered into the model as level terms. This presents no problem in interpretation, since they only enter as intercept or slope shifters. Further, the logarithmic specification required that we ignore those few observations in which LBMPs are negative. These usually occur in the morning hours, and we were not concerned with the morning hours in our models. The few instances of afternoon negative prices were in the first segment of the "spline"—the part of the supply function that is of little interest in our evaluation of EDRP and DADRP programs. We had to exclude them in our logarithmic formulation. The other advantages of the logarithmic specification (goodness of fit, flexibility as a functional form, and the ease in calculating supply price flexibilities) clearly outweighed this slight disadvantage.

of these variables in reflecting the situation depicted in Fig. 6-6. These variables do indeed improve the ability to model these supply relations.

Despite the excellent performance of these estimated functions, they do not pick up all the variation in LBMPs, There are a number of reasons why one could hardly expect them to do so. For example, although the scheduling algorithm in the real-time market, SCD, minimizes the cost of meeting load, real-time dispatch must also respond to immediate changes in system conditions. Since many of these actions are taken to ensure system security in the face of unforeseen circumstances, they would increase variability in LBMPs. Further, system security considerations often take precedence over economic considerations in selecting which units to dispatch in real time, and minimum run time bids influence real-time LBMPs as well through the hybrid pricing algorithm. It is not likely that all effects of these actions on the LBMPs in real time can be captured by variables that by necessity only reflect general changes in system conditions at the zonal level.

For our purposes, we are less interested in being able to forecast the change in actual LBMPs from hour-to-hour or day-to-day then we are in estimating the change in LBMPs due to marginal changes in load—load reductions in ICAP/SCR and EDRP. For this purpose, it is most important to have precise estimates of the model coefficients that are used to calculate the supply flexibilities. The high t-ratios on all the estimated coefficients, even after correcting for autocorrelation, are important indications that these marginal effects have been measured effectively.

Supply Price Flexibilities in the Real-Time Market for April 2002

Because of the need to include interaction variables in the models to isolate the effects of system conditions on LBMP, the supply flexibilities need not be constant in any regime, and they cannot be read directly from the models' coefficients. The ranges in supply price flexibilities for April 2002, as well as the average values, are reported in the bottom sections of Tables 6-3 through 6-5. Before discussing the supply flexibilities in the individual markets, there are also several general conclusions evident in the empirical results. First, the supply price flexibilities increase as load increases—as we move from regime 1 to regime 3 (see Fig. 6-2 and 6-6). Thus, the empirical results support the notion of a "hockey" stick shape for supply. At initially high levels of load served, small changes in load can have dramatic effects on LBMP.

In Neenan Associates (2002) previous evaluation of the PRL programs for 2001, it was suggested that the supply price flexibilities would be highest in markets where price variability was high relative to load variability, and average prices were high. Supply price flexibilities are indeed larger the real-time market in New York City and Long Island then they are for the Hudson "super" zone. This is consistent with the fact that price variability is higher in these two former zones, as are average prices. On average, the April supply flexibility (e.g. the percentage change in LBMP due to a percentage change in load) in the real time market in New York City is 13.06, which is 10 % higher than for Long Island (11.88), and over twice as large as for the Hudson "super" zone (5.69).

In the last part of the "spine" functions for all three zones, the supply flexibilities are affected by variables that shift the supply function. In some of the models, real-time load squared is used as a explanatory variable, as are variables that reflect the number of minutes in the previous or current hours that constraints transmission constraints were binding and the proportion of the current generation offered to maximum generation offered during the month system wide. This latter variable is designed to reflect the proportion of generation available in April (not on scheduled outage) that was bid into the system during a particular hour. One would expect prices to rise with the number of constraint minutes and fall as the proportion of maximum generation offered rises. As is seen in Tables 6-3 through 6-6 and the graphs in Appendix A, this is indeed what happens.

Supply Price Flexibilities in the Real-Time Market for the Summer 2002

Although we only needed supply curves for three of our supply regions to study the effects of the April EDRP events, we need supply relations for all five regions for the analysis of the summer 2002 EDRP events.

The two regions that were not needed in April are the Capital zone and the Western New York "super" zone (Tables 6-7 and 6-8). In the third part of the "spline" function price flexibilities averaged 6-67 and 5.97 for western New York and the Capital zone, respectively. A priori, one might have expected to see the higher average price flexibilities in the Capital zone, as was the case in the 2001 evaluation (Neenan Associates, 2002). However, this past summer there were some high prices in western New York, and it is clear that much to the extreme price responsiveness was also due to the effect of high loads in adjacent zones. It is this latter effect that is more pronounced in western New York than in the Capital zone.

As we expected, the supply equations for the real-time market during the summer of 2002 differ from those in April (compare Tables 6-3 through 6-6 and Tables 6-8 through 6-10 for the differences in the Hudson Region, New York City and Long Island, respectively). The average price flexibilities in the third part of the "spline" functions for these zones are 4.69, 12.82, and 5.16 in the Hudson Region, New York City, and Long Island, respectively. These averages are slightly lower than those for April, a surprising result at first glance given that there were no extreme prices in April. However, a careful examination of the data reveals that although prices in April never exceeded $350/MW in these regions, the supply curves still rise very steeply. Therefore, in percentage terms, prices rise considerably for small changes in load because of the low initial price against which the percentage changes are measured.

Further, the price data for high loads followed a more definite pattern during April; there greater complexity and interaction among zones during the summer led to a more diverse pattern of price and quantity combinations during the summer. As a result of this complexity, the range in elasticity values during the summer in these three zones is wider than in April.[14] This complexity also explains the negative flexibilities, which appear contour intuitive at first glance. However, it is in these negative flexibilities that explain the extremely low prices in some hours of high loads (e.g., the situations reflected in Fig. 6-5 and 6-6). Because of the influence of adjacent load, it is possible for a *ceteris paribus* change in load in one of these regions to lead to a drop in the LBMP, perhaps due to being now able to serve total load with a higher proportion of base load.

Supply Price Flexibilities in the Day-Ahead Market for the Summer 2002

We also need estimated supply flexibilities for the summer of 2002 in the day-ahead market in order to assess the performance of load bid in DADRP. These are reported in Tables 6-11 through 6-15. On balance, we were able to explain more of the variation in prices in these markets than in the real-time markets, and we were able to rely on the same types of "shifters" to accommodate some of the complexity inherent in price formation. As seen in Appendix A, the estimated supply equations, accommodating the extreme values these "shifters" track the data well. The average price flexibilities are 4.21, 4.96, 3.91, 3.55, and 6.52 in western New York, the

[14] It is for this reason that the supply functions plotted in Appendix A do not track the data for these regions in the summer to the same extent that they do in April. Still, there performance is rather remarkable given the small number of supply "shifters" for which data are available.

Capital zone, the Hudson Region, New York City, and Long Island, respectively. Within each zone, they do vary considerably around these mean values.

In general these averages are smaller than for real time, as one might expect, and they are smaller than for the summer of 2001 (see Neenan Associates, 2002). These lower values are undoubtedly explained in large measure by the fact that average summer prices in 2002 in the DAM were lower than last year, and were less variable as well.

Evaluation of the 2002 PRL Program Events

Somewhat unexpectedly, EDRP events were called as early as April 2002; the remaining events were called during late July and mid August, times during which one would most likely expect any system reliability problems due to peak loads on hot summer afternoons. After first describing these 2002 EDRP events, we summarize the strategy for evaluation and provide empirical estimates of these various effects. In most cases, these effects are broken out by pricing zone or "super" zone. Since the pricing zones were established for reasons other than overall system security, the discussion of this latter issue is most effectively done at the system level.

2002 EDRP Events

Because the supply models that must be used to estimate the effects of the April events differ from those for the summer events, we discuss the events separately. Moreover, the summer events were called statewide, and there were many more program participants during the summer events.

The April Events

These April events were called on April 17, from 12:00 noon to 6:00 pm, and on April 8, from 12:00 noon to 6:00 pm. These events were called primarily for the pricing zones in the lower Hudson Valley (G, H, and I) and New York City (J) and Long Island (K). On April 18, the events were also called in the Genesee zone (B).[15]

The April events were called prior to the May 31, 2002 deadline for program enrollment. Based on data supplied by the NYISO, the total program participants at that time numbered 333

[15] Because of the low prices in Western New York and difficulty in modeling supply for a single zone in Western New York, it was impossible to estimate any market effects in that one zone.

(including the 116 combined EDRP/SCR participants), essentially those firms enrolled in the 2001 programs (Table 6-16). There were an additional 94 customers enrolled only in the ICAP/SCR program.[16] The average hourly load reductions from EDRP participants during the April events are given by zone in Table 6-17. During the April event hours, there were on average 36.1 MW of PRL load reduction (Table 6-17, column d); 61% of the EDRP load reduction came from New York City (Table 6-17, column d). Another 22% was from the Hudson Region, while the remaining 17% was from Long Island (Table 6-17, column d).

The Summer Events

In contrast to the April events, the 2002 EDRP events of July 30, from 1:00 pm to 6:00 pm, and August 14, again from 1:00 pm to 6:00 pm, were called statewide. Further, these events occurred after the deadline for 2002 enrollment, and the load reduction realized reflects the substantial increases in the numbers of customers and subscription in both SCR and EDRP over and above the 2001 levels.

At the time the summer 2002 events were called, there were a total of 1,785 customers enrolled in the EDRP and SCR programs, up from 395 in 2001 (Table 6-18, column d). Of this total, 1,534 end-use customers enrolled only in EDRP; another 177 customers were enrolled in both SCR and EDRP, while 74 customers were enrolled only in SCR (Table 6-18). Western New York had 519 PRL program participants (Table 6-18, column d). Long Island has over 900 PRL participants, but the vast majority of them are small residential customers belonging to a direct load control program (Table 6-18, column d).

Due to the increased enrollment, at the time of the summer events there over 1,478 MW subscribed to EDRP (sum of columns e and h, Table 6-18), and 681 MW subscribed to SCR (sum of columns f and g, Table 6-18). To the extent that between 500 MW and 600 MW of SCR and EDRP loads are subscribed to joint program participants, it is unlikely that these are independent amounts of load reduction resources. To assume so would most likely be double counting the potential load reduction available during an EDRP event. Because of the number of customers and their size, it is not surprising that the largest proportion of subscribed MW is found in

[16] The distribution of EDRP customers in the 2001 programs by zone and type of program provider is in Table 1.12 of the 2001 evaluation report (Neenan Associates, 2001).

Western New York. This has not changed from last year, although subscription levels in the City and Long Island have increased disproportionately to those of the other zones.

As one would expect, the hourly load reductions from EDRP participants during the July and August events were much higher, averaging 663.2 MW (Table 6-19, columns d and j, respectively). Western New York accounted for 61% of the SCR and EDRP load reduction, while the Capital zone accounted for 10% of the EDRP load reduction (Table 19, columns d and j). New York City accounted for 13% of the EDRP load reduction and 10% of the SCR load reduction. Long Island accounted for 11% of the EDRP load reduction, while the Hudson region accounted for the remaining 5%.

Overall Strategy for Evaluating the Effects of the PRL Programs

The overall strategy for evaluating the effects of the PRL programs, and a list of the major market effects are given in Fig. 6-6. These effects include:

- Estimated changes in electricity prices;
- Estimated collateral benefits—redistribution of payments from generators to customers, or vice versa;
- Effect of program on system reliability;
- Program costs; and
- Estimated reduction in risk.

We begin with an evaluation of the EDRP events and then proceed to the evaluation of DADRP.

The EDRP Evaluation

The theory underlying the effect of load reduction or on-site generation during an EDRP event is developed in detail in earlier reports to the NYISO by Neenan Associates (2001 and 2002). It need not be repeated here.

To estimate the effects of the EDRP events on LBMP in real time, we must perform two sets of simulations for each pricing zone or "super" pricing zone. The simulations are:

1. The first set of simulations is designed to calculate a set of base prices in the real-time market for the hours in the April, July, and August 2002 emergency events. These prices

for the event hours are calculated by adding back into load the load reduction from EDRP. These reflect the prices at which the market would have cleared had the load reduction measures been taken. These base prices are thus the appropriate ones against which to compare the prices resulting from the partial dispatch of the 2002 EDRP load reduction.

2. The second set of simulations is designed to estimate the additional effect on LBMP in real time if EDRP resources are dispatched in addition to resources in ICAP/SCR.

In these simulations we assume that EDRP resources cannot set LBMP, although there has been some discussion that this will change for next year's program.

Effects of the April 2002 EDRP Events

Effects on LBMP's

The effects of the April 2002 EDRP events on the real-time electricity market in New York State are also provided in Table 6-17.[17] As stated above, there was, on average, about 36.1 MW of hourly load reduction during these events. During those hours, LBMP in real time averaged $215/MW, $209/MW and $187/MW in New York, Long Island, and the Hudson River region, respectively (Table 6-17, column e). Had this load reduction not been delivered by EDRP participants, our simulations estimated that the average LBMPs in real time would have been somewhat higher, $223/MW, $215/MW and $191/MW in New York, Long Island and the Hudson River region, respectively (Table 6-17, column c). [18]

These implicit price reductions due to EDRP load curtailments are modest since load reductions as a percent of real time load averaged less than 0.3% in all of the regions (Table 6-17, column f). Thus, although the supply flexibility in New York was on average over 13 during the month of April (Table 6-17, column h), the average hourly reduction in LBMP due to EDRP curtailments was only 3.42% (Table 6-17, columns g). The average reductions in LBMP in the other zones were smaller still, 2.18% and 1.63% in Long Island and the Hudson region,

[17] The hourly results are detailed in Appendix B.

[18] As described in Neenan 2001, supply flexibility models are used to simulate what the price otherwise would have been. The supply flexibility is defined as the percentage change in price due to a one percent change in load.

respectively (Table 6-17, columns g), despite average supply flexibilities of about 6 and over 11, respectively (Tables 6-5 and 6-6).

One consequence of the decline in NYISO real-time prices due to the EDRP curtailments is that there would have been some transfers from generators to LSE's (perhaps ultimately to customers) relative to what would have happened without the load reductions. From a customer perspective, these can be called collateral benefits. From last year's evaluation (Neenan Associates, 2002), the collateral savings are defined as the real-time LBMP price change due to the EDRP participant load reductions multiplied by the difference between the loads served in real time and those served in the DAM. This is the energy that is settled in the real time market.

The transfers from generators to others are estimated to equal $358,874 (columns i in Table 6-17); 82% ($293,433) are associated with load curtailments in New York City. On an hourly basis, these collateral benefits averaged $24,453, $948, and $4,506, in New York City, on Long Island and in the Hudson River Region, respectively (Table 6-17, column i).

Program Payments

The distribution of EDRP program payments to participants, which totaled $216,583, is summarized in Table 6-20. Of the total, 58% were to participants in New York City, while another 17% went to participants in Long Island. About 21.5% went to customers in the Hudson River Region, and the remaining 3.4% was paid to participants in Western New York.

Effects on Average LBMP and its Variability

As discussed in the 2001 evaluation (Neenan Associates, 2002), the collateral benefits arising from load curtailments mentioned above are transfers to buyers from sellers. However, by affecting the number of extreme prices, EDRP load curtailments reduce both average LBMPs and the variability in LBMPs, thus adding importantly to the liquidity of the market.[19]

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[19] There is no need in this report to discuss in detail the role of mean price and price variability in affecting the value of an investment or portfolio. The results are well known and the details can be found in standard texts such as Sharpe, Alexander and Bailey (1995, Chapters 6-8), and the associated references. In theory, one would ultimately expect the price of hedging contracts to reflect both average price reductions and reductions in price variability. It is easy to calculate the cost reduction due to lower average prices simply by accounting for the differences in average prices Note that these benefits reflect the available PRL load. If more loads participate, or participant price elasticity increases, then so do the benefits.

In considering these potential cost savings, it is important to emphasize that these estimates are probably lower bounds on the actual saving because they don't reflect any cost reduction due to the fact that prices are less variable as well. To estimate the effect of lower variability on the price of hedges, it would be

From the data in Table 6-21, one can see this is the case, although the effects are very small.[20] But, given the relatively small amount of load reduction in these April events, one could hardly expect otherwise. The average LBMP for the hours from 6:00 a.m. to 10:00 p.m. during weekdays in April were lower than they would have been without the EDRP load reduction by about $0.27/MW in the City, and by about $0.18MW and $0.11/MW on Long Island and in the Hudson Region, respectively (Table 6-21, column g). The standard deviations in prices in all three zones fell slightly as well (compare column b with column e in Table 6-21). If these slightly lower prices were reflected in the long-term cost of hedging load, the savings would be estimated at $260,780 (Table 6-21, column h).

Effects of the Summer 2002 EDRP Events

Effects on LBMP's

The effects of the summer 2002 EDRP events on the real-time electricity market in New York State are also provided in Table 6-19.[21] As stated above, there was, on average, about 663.2 MW of hourly load reduction during these events. During those hours, LBMP in real time averaged $93/MW, $99/MW, $161/MW, $54/MW, and $87/MW in the Capital Zone, New York City, Long Island, the Western Region, and the Hudson River region, respectively (Table 6-19, column e). Had this load reduction not been delivered by EDRP participants, our simulations estimated that the average LBMPs in real time would have been somewhat higher, $114/MW, $107/MW, $177/MW, $74/MW, and $92/MW in the Capital Zone, New York City, Long Island, the Western Region, and the Hudson River region, respectively (Table 6-19, column c). [22]

These implicit price reductions due to EDRP load curtailments are significant in some pricing zones due to a combination of the relative load reduction, and the relatively high price

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necessary to have information about how risk- averse purchasers of electricity are as a group (e.g. the extent to which they discount price risk in their hedging decisions). Alternatively, a financial model that reliably produced hedge prices using price means and variances would indicate the value of PRL loads. These results are beyond the scope of this study.

[20] These effects would be even more modest, or could actually be reversed in the event that SCR and EDRP load reductions are allowed to set LBMPs according to the current hybrid pricing rules in those pricing intervals when the load reduction is needed to maintain system reserves.

[21] The hourly results are detailed in Appendix D.

[22] As described in Neenan 2001, supply flexibility models are used to simulate what the price otherwise would have been. The supply flexibility is defined as the percentage change in price due to a one percent change in load.

flexibilities of supply. As a result of EDRP, load in these event hours was reduced in these hours by an average of 4.41%, 3.15%, and 1.53% in the Western Region, the Capital Zone, and Long Island, respectively. Load was reduced by less than 1% in both the Hudson Region and New York City (Table 6-19, column f). Thus, although the supply price flexibilities in the Capital Zone and the Western Region were lower on average during these hours than in New York (Table 6-19, column g), the average hourly reduction in LBMP due to EDRP curtailments were estimated to be 20.05% and 25.09% in the Capital Zone and the Western Region, respectively—between two and three times the 7.36% reduction in New York City (Table 6-19, columns g).

One consequence of the decline in NYISO real-time prices due to the EDRP curtailments is there would have been some transfers from generators to LSE's (perhaps ultimately to customers) relative to what would have happened without the load reductions, From a customer's perspective, these can be called collateral benefits. From last year's evaluation (Neenan Associates, 2002), the collateral savings are defined as the real-time LBMP price change due to the EDRP participant load reductions multiplied by difference between the loads served in real time and that served in the DAM. This is the energy that is settled in the real time market.

The transfers from generators to others are estimated to equal $577,979 (column i in Table 6-19); 53% ($305,761) are associated with load curtailments in New York City. Another 21% of the collateral benefits were in the Western Region, while shared in the Hudson Region and the Capital Long Island were 10% and 12 %, respectively. The Capital Zone received the remaining 5% (Table 6-19, column i).

Program Payments

The EDRP program payments for EDRP for the July 30 and August 14, 2002 summer events are given in Table 6-22. In total, payments equaled $3,318,381. The lion's share (61%) of the payments went to participants in the Western New York Region, while 13% went to participants in New York City, 11% went to Long Island participants, 10% went to the Capital zone, and the remaining 5% went to customers in the Hudson River Region. In contrast to last year, real-time LBMPs during the event hours never exceeded $500/MW in any pricing zone, so payments are distributed in exactly the same proportion as a zone's contribution to overall EDRP performance.

Effects on Average LBMP and its Variability

As stated above, these collateral benefits arising from load curtailments during the summer of 2002 are transfers to buyers from sellers. However, by affecting the number of extreme prices, one might also expect EDRP load to reduce both average LBMPs and the variability in LBMPs, thus adding importantly to the liquidity of the market.

Although these effects are relatively modest, they are similar on an hourly basis to those from last year's EDRP events (Neenan Associates, 2002), and if these programs persist in the long run and market participants come to expect that real-time LBMPs are likely to be lower and less variable, eventually this influence will be reflected in the prices at which customers can hedge load, either through physical bilateral supply contracts or financial hedges.

The average real-time LBMPs for the hours from 6:00 a.m. to 10:00 p.m. during weekdays in July and August were lower than they would have been without EDRP event load reduction by $0.20/MW in the Capital Zone and by $0.19/MW in Western New York (compare columns a and d in Table 6-23). The average price reductions are even smaller for the other zones, ranging from a reduction of $0.15/MW on Long Island and $0.08/MW in New York City to only $0.04/MW in the Hudson River Region (compare columns a and d in Table 6-23).

The standard deviations in LBMPs fall as well, by a high of $0.23/MW and $0.22/MW on Long Island and in the Capital Zone, respectively, to lows of $0.10/MW in both New York City and Western New York and $0.05/MW in the Hudson River Region (compare columns b and e in Table 6-23).

Based on these estimated price changes, the estimated long-term reduction in the cost of hedging load would total $330,307 (column h of Table 6-23). Of this total, about 56% would accrue to customers in Western New York and about 19% would accrue in New York City (calculated using column h of Table 6-23). Long Island would see 22% of these cost reductions, while the Capital Zone would see 12% and the Hudson River Region would receive just over 3%.

Effects of both the April and Summer EDRP Events on System Reliability

Load reduction during EDRP events will also affect the reliability of New York's entire electricity system. Indeed, some might argue that this purpose, and this purpose alone, justifies an emergency program and dictates how it should be deployed and participants should be paid. After all, the name *emergency program* implies that it would be utilized when market operations fail to provide the desired level of system security. Regardless of whether one holds this view, clearly

the positive effects of EDRP on system reliability are an essential component of the program's benefits, and should be included in assessing the program's market effects.

Conceptually, the effects of EDRP load reduction on system security are more difficult to define than are the collateral benefits of or the potential effects on the cost of hedging load, and they are certainly more challenging to estimate empirically. To begin to understand this measure of benefits, it should be noted that a forecasted deficiency in operating reserves allows the NYISO to count EDRP load and Special Case Resources as operating reserve in order to assist in eliminating the shortfall (NYISO Emergency Operations Manual, 2001). Therefore during both the April and summer events of 2002, EDRP and Special Case Resources were deployed by the NYISO, perhaps along with more conventional actions, such as voltage reduction and external emergency energy purchases, in effect confirming that at least one role of these programs is to provide the system with emergency operating reserves.

We can assess the benefits of EDRP load in terms of its effect on system security by looking at how an increase in reserves would reduce the Loss of Load Probability (LOLP) and thereby reduce the costs associated with brownouts and blackouts that result in un-served energy.[23] Fig. 6-8 depicts graphically the relationship between reserves and LOLP. As seen in the graph, the LOLP associated with 100% of the required reserves (point a) is very small. However, as reserves fall below this required level (moving to the left of point a), the LOLP begins to rise, gradually at first, but as reserves continue to fall, LOLP rises much more rapidly, approaching 1 as reserves approach zero. Thus, as system operators forecast a reserve shortfall, the system state is represented by a point such as b. By calling EDRP, the load reduction works to restore reserve margins—thus moving the system from point b to the right toward point a. The extent to which reserve margins are completely restored is a function of the amount of load reduction or on site generation that is provided by EDRP participants. As is apparent in the data provided by the NYISO, this load reduction was sufficient to restore reserves during some hours or portions of hours during both the April and summer EDRP events. In other hours, they only partially restored reserve margins to 100% level (Fig. 6-9).

From this perspective, a measure of the benefits of EDRP can be defined by the change in the Value of Expected Un-served Energy (VEUE), as follows:

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[23] This interpretation is consistent with how Analysis Group (1991) valued load reduction in its early 1990s voluntary interruptible load program (VIPP).

(24) ΔVEUE = (Change in LOLP) * (Outage Cost/MW) * (Un-Served Load in MW)

The change in the VEUE, labeled ΔVEUE quantifies the impact on end-use customers of service interruptions. If the deployment of EDRP resources results in a positive change in VEUE, then that benefit qualifies as a contribution to system security.

To estimate ΔVEUE, one must know the relationship between the system reserve margin and the probability of an outage (Change in LOLP), as well as the cost incurred by customers from an outage (Outage Cost/MW) and the amount of un-served energy associated with the situation under evaluation (Un-Served Load MW). While these factors all have a sound basis in engineering and economic principles, none of these pieces of information is readily quantifiable from conventional market transactions data.[24] Put differently, in order to make a direct application of equation (24) for estimating the change in the expected value of un-served energy due to an EDRP load reduction, one would clearly need to estimate the relationship between reserve levels and the loss of load probability (e.g., the relationship in Fig. 6-8) for the entire New York State electricity market to effect the most appropriate comparison of EDRP payments relative to the value of EDRP load reduction in restoring system security. This could only be accomplished by the NYISO through a production system simulation analysis conducted from a total system-wide planning perspective. This type of analysis was clearly beyond the scope of this research.

Furthermore, only a handful of comprehensive studies to estimate outage costs have been completed in the past 15 to 20 years. Fortunately, one of the most comprehensive studies was conducted by Niagara Mohawk Power Corporation in the early 1990's. In that study, the average outage costs for industrial and commercial customers were estimated at $7,400/MWh (Analysis Group, 1990). However, in a subsequent study evaluating Niagara Mohawk's Voluntary Interruptible Pricing Program (Analysis Group, 1991), Analysis Group used a range of outage costs from $500/MWh to $15,000/MWh to calibrate their demand models.[25] This broad range in values was used because of the subjectivity associated with the initial outage cost estimates. The

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[24] A discussion of how outage cost and LOLP are conceptualized and measured, see Chao, H.P., R. Wilson (1987).

[25] RTP programs operated by many vertically integrated utilities derived the LOLP/Reserves curve using production simulation models and then established an hourly outage costs by tracing the hour's reserve against the curve and multiplying the corresponding LOLP by an established value for outage cost, usually a value of one to two dollars per kWh.

British PoolCo model, which required a value for lost load, adopted a value of approximately $2,500/MWh.[26]

To circumvent these problems, we begin the analysis of the system-wide security benefits of EDRP load reduction by solving equation (24) for the un-served load (e.g. the load that would need to be at risk in order ΔVEUE to exactly to EDRP program payments to customers). This essentially is the load at risk that would be needed for the program to "break even" if the only benefits considered are those from changes in system security. Solving equation (24) for the change in LOLP, we have:

(25) (Un-Served Load in MW) = [ΔVEUE] / [(ΔLOLP) * (Outage Cost/MW)]

We can now evaluate this equation for alternative estimates of outage costs and a range in values for the ΔLOLP.[27] Recalling that the EDRP payments to customers are $216,583 and $3,318,381 for the April and summer events, respectively, these calculations (for four alternative outage costs and six reductions in LOLP) are presented in Tables 6-24 and 6.25.

Perhaps the most striking feature of the results of this analysis for the April events is that under the most conservative assumptions about both outage costs (e.g. $1,000/MW) and the reduction in LOLP (e.g. 0.05) only 3.6% of the load would have had to be at risk in order for the benefits in terms of VEUE to exceed the program costs (column a of Table 6-24). If one assumes that either the reduction in LOLP due to EDRP load is larger or if outage costs exceed $1,000/MW the load at risk needed for the benefits to outweigh the costs falls rapidly. At the other extreme (where outage costs are assumed to be $5,000/MW and the change in LOLP is assumed to be 0.50), only 0.1% of load would have to be at risk for the program benefits to equal program costs.

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[26] Patrick and Wolak (2000) estimate that in the England and Wales power markets, the outage costs, or willingness to pay to avoid supply interruptions during 1990/91 was £2,000/MWh (approximately $2.50/kWh), and that increased steadily in subsequent years with the growth of the Index of Retail Prices. In 2001, Britain converted from central pool pricing to bilateral markets and as a result the value of lost load is no longer used directly to set market prices.

[27] To account for the fact that EDRP load could be equal to, fall short of, or exceed the reserve shortfall during any five-minute interval of an event hour, we multiplied the outage cost by the proportion EDRP contributed to total reserve shortfall during all intervals of the event hours. In this way, we are effectively assuming that outage costs are zero in those portions of the hour in which EDRP load was not needed to restore system reserves. These adjustments are based on interpolations from the graphic display of EDRP load and system-wide provided by NYISO.

As seen from a slightly different perspective, in Appendix Tables 6-1D and 6-2D, the system security benefits due to the April EDRP load reduction could be small if only a small fraction of load had been at risk or could exceed program costs by several orders of magnitude if all or nearly all load had been as risk of an outage. For the April events, system security benefits would fall short of program costs only under the most conservative assumptions: no greater than 5% of the load was at risk; outage costs were no greater than $1000/MW; and the load reduction led to a decrease in LOLP of no more than 0.05.

The situation is not so clear-cut for the summer events. In contrast to the April results, under the most conservative assumptions about both outage costs (e.g. $1,000/MW) and the reduction in LOLP (e.g. 0.05) 48.9% of the load would have had to be at risk in order for the benefits in terms of VEUE to exceed the program costs (column a of Table 6-25). It remains true that the load at risk needed for the benefits to outweigh the costs falls rapidly if one assumes that either the reduction in LOLP due to EDRP load is larger or if outage costs exceed $1,000/MW. However, at outage costs of $1,000/MW, the load at risk needed to equate VEUE benefits to program costs would remain above 20% until the reduction in LOLP due to EDRP load relief exceeds 0.10 (column a of Table 6-25). Alternatively, of a reduction in LOLP of only 0.05, the percentage of the load at risk needed to equate VEUE benefits to program costs would fall to 9.8% if outage costs were assumed to be $5,000/MW.

Again, as seen from a slightly different perspective in Appendix Tables 6-3D and 6-4D, the system security benefits due to the April EDRP load reduction could be small if only if a small fraction of load had been at risk or could exceed program costs by several orders of magnitude if all or nearly all load had been as risk of an outage. For the summer events, system security benefits would fall short of program costs if only 5% of the load had been at risk except under the assumption that outage costs are at least $5,000/MW or the load reduction led to a reduction in the LOLP of at least 0.20. If a somewhat larger share of the load were at risk, it is likely that the benefits in terms of VEUE would exceed program costs. Clearly, in this case, as well as in April, if nearly all load had been at risk, benefits would always exceed program costs, and often many times over.

Effects of the Summer 2002 DADRP Bidding Activity

Our analysis of the effects of bidding in the day-ahead market is limited to the activity during the summer months of 2002. It is in these months that the effects of load reduction on

prices in the DAM are of most interest, and because the primary focus of the EDRP evaluation was on the summer events, the NYISO was able to make price and fixed bid load data for the DAM in the summer months available without much additional effort. It is these data that were needed to estimate the supply curves for the DAM.

According to records supplied by the NYISO, there are currently 24 customers participating in the DADRP. Most, but not all are located in the Capital district and in Western New York, and it is only in these regions that any DADRP were accepted during the months of June, July, and August. There were 158 hours during which bids were accepted in the Capital Zone, and 59 hours for which bids were accepted in western New York. The effects on the DAM from these bids accepted in DADRP are summarized in Tables 6-26, 6-27, and 6-28.

The Effects on LBMP in the DAM

The aggregate and hourly effects of DADRP bidding on prices in the DAM are given in Table 6-26.[28] For the three summer months, there were a total of 1,468 MW of bids accepted in the DAM; 29% of this total was from customers in western New York, while the remaining 71% was in the Capital region (Table 6-26, column d). The average hourly load reduction in both zones was 7 MW (Table 6-26, column d). In these hours, this load reduction represented 0.4% of the fixed bid load in the DAM for the Capital region, and 0.1% of the fixed bid load in western New York (Table 6-26, column g). The changes in hourly LBMPs in the DAM due to this load reduction averaged 1.1% in the Capital region and 0.4% in western New York (Table 6-26, column h).

These modest price reductions in the DAM led to an estimated revenue transfer of $394,574 in collateral benefits from generators to wholesalers, assuming that all fixed bid load was settled in the DAM (Table 6-26, column k). However, it is estimated that only about 60% of the fixed bid load is settled in the DAM (40% through bilateral contracts); thus, actual collateral transfers would be only $236,745 (Table 6-26, column l).

Program Payments

Program payments for DADRP are summarized in Table 6-27. Of the $110,216 in total payments, 75% went to customers in the Capital zone, while the remaining 25% was paid to

[28] The hourly details are given in Tables in Appendix E.

customers in western New York (Table 6-27). Average hourly payments were somewhat higher in the Capital zone as well ($521 vs. $473).

Effects on Average LBMP and its Variability

Because of the very modest decreases in LBMPs in the DAM due to the activity in DADRP, it is not surprising that the effects of this program on average summer prices in the DAM and price variability were extremely modest as well (Table 6-28). Average prices in the Capital zone would have fallen between $0.06/MW and $0.21/MW in these months, while the reduction would have been no more than $0.04 during any of the months in western New York (Table 6-28, column g). The estimated reduction in the long-term cost of hedging would have been $202,349—73% accruing in the Capital zone (Table 6-28, column h).

Table 6-1 Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (April 2002, Afternoon Hours) *

Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
West of Total East (Zones A, B, C, D & E)				
Maximum	6,374	$56	7,377	$88
Mean	5,507	$32	6,459	$28
Minimum	4,548	$19	5,373	$5
Standard Deviation	421	$7	520	$10
Capital (Zone F)				
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	1,265	$88	1,572	$121
Mean	1,030	$43	1,275	$38
Minimum	794	$29	1,029	$19
Standard Deviation	98	$11	124	$13
Hudson River (Zones G, H & I)				
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	1,608	$78	3,030	$281
Mean	1,342	$44	2,044	$47
Minimum	1,153	$31	1,139	$20
Standard Deviation	90	$9	321	$39
New York City & Long island (Zones J & K)				
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Maximum	8,867	$197	12,064	$321
Mean	6,846	$49	8,547	$52
Minimum	5,585	$34	6,809	$21
Standard Deviation	727	$23	1,205	$45

* Afternoon hours correspond to 1:00 p.m. through 7:00 p.m. Prices in zonal aggregates are load weighted averages.

Table 6-2 Summary Data for Hourly LBMP and Load by Zonal Aggregates for Which Separate Supply Functions are Estimated (Summer, Afternoon Hours, 2002)*

	Capital (Zone F)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	901	$25	1,114	$12
Maximum	1,928	$214	2,108	$1,008
Mean	1,413	$58	1,594	$49
Standard Deviation	246	$31	242	$66
	New York City (Zone J)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum		$29		$21
Maximum		$199		$1,123
Mean		$76		$71
Standard Deviation		$32		$74
	Long Island (Zone K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum		$37		$21
Maximum		$601		$1,109
Mean		$87		$81
Standard Deviation		$72		$77
	West of Total East (Zones A, B, C, D, & E)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	4,701	$17	5,345	$12
Maximum	8,882	$158	9,506	$996
Mean	6,643	$47	7,460	$44
Standard Deviation	925	$25	927	$64
	Hudson River (Zones G, H, & I)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	1,193	$24	1,884	$13
Maximum	2,700	$197	4,031	$1,106
Mean	1,843	$59	2,858	$55
Standard Deviation	387	$30	555	$73
	New York City & Long Island (Zones J & K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	6,331	$32	7,373	$24
Maximum	11,384	$375	15,443	$1,118
Mean	9,107	$81	11,525	$74
Standard Deviation	1,170	$45	2,091	$74
	New York State (Zones A - K)			
Statistic	DAM Bid Load (MW)	DAM LBMP ($/MW)	RT Load (MW)	RT LBMP ($/MW)
Minimum	13,229	$28	16,212	$22
Maximum	24,359	$228	30,664	$1,072
Mean	19,006	$65	23,438	$61
Standard Deviation	2,619	$33	3,707	$69

*For June, July and August, 1:00 pm through 7:00 pm. Prices in zonal aggregates are load weighted averages.

** It is NYISO policy not to report load separately for New York and Long Island.

Table 6-3 Estimated Real Time Electricity Supply Function, Hudson Super Zone, April 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-1.2552	-1.84		
Real-Time Load			0.6238	7.03	5.1082	7.11
Trans. Const. Wt. by Load					0.2128	3.55
Proportion of Gen. Offered	-2.8526	-5.64	-2.8526	-5.64	-2.8526	-5.64
Arch (0)	0.0107	6.65				
Arch (1)	1.0989	4.55				
Arch (2)						
R^2 =	0.6976					
	Knots (% of Maximum Load)					
Price Flexibilities**			10.0		68.5	
Minimum	0.00		0.62		5.10	
Maximum	0.00		0.62		8.57	
Mean	0.00		0.62		5.69	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-4 Estimated Real Time Electricity Supply Function, New York City, April 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-29.9625	-3.08		
Real-Time Load	2.6237	12.06	3.8310	3.50		
Real-Time Load Squared					0.4845	6.11
Proportion of Gen. Offered					-69.1351	-7.94
Lag.Trans. Const. Wt. by Load	0.0001	0.13	0.0001	0.13	0.0001	0.13
Arch (0)	0.0054	3.55				
Arch (1)	0.8616	3.56				
Arch (2)	0.3443	2.24				
R^2 =	0.8701					
	Knots (% of Maximum Load)					
Price Flexibilities**			45.0		60.0	
Minimum	2.62		3.83		10.04	
Maximum	2.62		3.83		15.95	
Mean	2.62		3.83		13.06	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifterif the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-5 Estimated Real Time Electricity Supply Function, Long Island, April 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-59.0869	-13.90		
Real-Time Load	1.3431	7.45	7.9871	14.85		
Real-Time Load Squared					0.7358	13.16
Trans. Const. Wt. by Load			0.0001	3.01		
Arch (0)	0.0035	2.10				
Arch (1)	0.8035	4.04				
Arch (2)	0.5458	3.99				
R^2 =	0.5508					

	Knots (% of Maximum Load)		
Price Flexibilities**		35.0	59.0
Minimum	1.34	7.99	11.76
Maximum	1.34	7.99	11.96
Mean	1.34	7.99	11.88

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-6 Estimated Real Time Electricity Supply Function, Western NY Super Zone, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-22.2721	12.37		
Real-Time Load	1.0473	1.53	2.8851	14.37	-953.2731	-12.23
Adjacent Zonal Load					114.4911	12.37
Arch (0)	0.0451	19.85				
Arch (1)	0.6698	8.24				
Arch (2)						
R^2 =	0.6084					
	Knots (% of Maximum Load)					
Price Flexibilities**			30.0		75.0	
Minimum	1.05		2.89		-11.10	
Maximum	1.05		2.89		15.39	
Mean	1.05		2.89		6.67	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-7 Estimated Real Time Electricity Supply Function, Capital Zone Super Zone, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-11.3357	-3.03		
Real-Time Load	1.8765	11.79	2.0197	4.05	-637.8404	-2.56
Adjacent Zonal Load					82.0124	2.59
Wgt. Transmission Const.	0.0051	4.10	0.0051	4.10	0.0051	4.10
Arch (0)	0.0544	16.07				
Arch (1)	0.6686	6.74				
Arch (2)						
R^2 =	0.5543					

	Knots (% of Maximum Load)		
Price Flexibilities**		60.0	80.0
Minimum	1.88	2.10	-4.30
Maximum	1.88	2.10	10.94
Mean	1.88	2.10	5.97

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-8 Estimated Real Time Electricity Supply Function, Hudson Super Zone, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-13.0014	-3.75		
Real-Time Load	1.9250	14.52	2.0974	4.92	-1122.0000	-6.58
Adjacent Zonal Load					115.1531	6.62
Arch (0)	0.0387	11.12				
Arch (1)	0.7482	7.81				
Arch (2)						
R^2 =	0.6555					
	Knots (% of Maximum Load)					
Price Flexibilities**			57.5		75.0	
Minimum	1.93		2.10		-8.47	
Maximum	1.93		2.10		10.66	
Mean	1.93		2.10		4.69	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-9 Estimated Real Time Electricity Supply Function, New York City, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-62.5755	-11.20		
Real-Time Load	1.9621	19.10	7.3021	11.99		
Real-Time Load Squared					0.6930	3.98
Proportion of Off. Gen. Bids	-1.4157	-4.19	-1.4157	-4.19	-1.4157	-4.19
Arch (0)	0.0325	10.23				
Arch (1)	0.6491	7.17				
Arch (2)						
R^2 =	0.6656					
	Knots (% of Maximum Load)					
Price Flexibilities**			77.5		90.0	
Minimum	1.96		7.30		12.76	
Maximum	1.96		7.30		12.79	
Mean	1.96		7.30		12.82	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-10 Estimated Real Time Electricity Supply Function, Long Island, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-44.3926	-20.96		
Real-Time Load	0.4610	2.05	4.283	13.76		
2-Lag Wgt. Trans. Const.					-0.6104	-5.40
Real-Time Load Squared					0.8798	5.70
Adjacent Zonal Load	1.4393	5.37	1.4393	5.37	1.4393	5.37
Arch (0)	0.0285	6.87				
Arch (1)	0.7571	4.65				
Arch (2)						
R^2 =	0.7406					
	Knots (% of Maximum Load)					
Price Flexibilities**			60.0		87.5	
Minimum	0.46		4.28		-7.39	
Maximum	0.46		4.28		8.12	
Mean	0.46		4.28		5.16	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-11 Estimated Day Ahead Electricity Supply Function, Western NY Super Zone, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-18.1659	-7.29		
Fixed Bid Load	2.3107	29.17	2.4806	8.82	-78.9708	-2.20
Proportion of Gen. Offered					-46.5309	-10.88
Adjacent Zonal Load					9.9067	2.26
Arch (0)	0.0052	0.00				
Arch (1)	0.8078	5.13				
Arch (2)						
R^2 =	0.8384					

	Knots (% of Maximum Load)		
Price Flexibilities**	45.0	60.0	
Minimum	2.31	2.48	1.46
Maximum	2.31	2.48	7.10
Mean	2.31	2.48	4.21

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-12 Estimated Day Ahead Electricity Supply Function, Capital Zone, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-18.6887	-13.77		
Fixed Bid Load	1.2455	18.78	3.0852	16.77	1.6304	2.43
Proportion of Gen. Offered					-60.6415	-7.92
Arch (0)	0.0084	7.04				
Arch (1)	0.8786	5.07				
Arch (2)						
R^2 =	0.7007					

	Knots (% of Maximum Load)		
Price Flexibilities**		55.0	75.0
Minimum	1.25	3.09	1.95
Maximum	1.25	3.09	7.79
Mean	1.25	3.09	4.96

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-13 Estimated Day Ahead Electricity Supply Function, Hudson Super Zone, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			7.1917	-24.13		
Fixed Bid Load	1.0240	13.83	1.4715	37.88	-205.7204	-3.47
Proportion of Gen. Offered					-118.8051	-9.78
Adjacent Zonal Load					21.3135	3.43
Arch (0)	0.0045	6.23				
Arch (1)	1.2500	8.19				
Arch (2)						
R^2 =	0.6612					
	Knots (% of Maximum Load)					
Price Flexibilities**		30.0		80.0		
Minimum	1.02		1.47		-3.66	
Maximum	1.02		1.47		9.11	
Mean	1.02		1.47		3.91	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-14 Estimated Day Ahead Electricity Supply Function, New York City, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-15.9041	-5.99		
Fixed Bid Load	1.6828	1.33	2.3107	7.49	-61.4152	-15.50
Proportion of Gen. Offered Adjacent Zonal Load					-14.2942	-4.94
Arch (0)	0.0059	16.44				
Arch (1)	0.9305	6.41				
Arch (2)						
R^2 =	0.6163					

	Knots (% of Maximum Load)		
Price Flexibilities**		15.0	40.0
Minimum	1.68	2.31	-0.01
Maximum	1.68	2.31	6.49
Mean	1.68	2.31	3.55

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-15 Estimated Day Ahead Electricity Supply Function, Long Island, Summer 2002

	The Segments of the "Spline" Supply Function					
	Segment 1		Segment 2		Segment 3	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant			-18.5048	-17.82		
Fixed Bid Load	0.9444	7.94	2.7750	22.09	1.3877	2.56
Proportion of Gen. Offered					-100.0372	-15.17
Arch (0)	0.0164	7.86				
Arch (1)	0.8355	6.56				
Arch (2)						
R^2 =	0.7473					
	Knots (% of Maximum Load)					
Price Flexibilities**			30.0		80.0	
Minimum	0.94		2.77		1.46	
Maximum	0.94		2.77		11.68	
Mean	0.94		2.77		6.52	

* Variables are defined in Appendix Table 6.1A; All are in logarithms, except where noted.
The model estimated is from equation (11), and the coefficients are those associated with intercept shifter if the same coefficients appear in all segments of the spline.
The other slope shifter variables are formed by multiplying the logarithm of load and the logarithm of the variable listed in the left-hand column.
** Since there are slope shifters in the model, the price flexibilities of supply are different at each data point, and they are calculated according to a generalized version of equations (18-20) in which there is more than one interaction variable with the logarithm of load served.
Note: the ARCH variables correct for serial correlation in the errors.

Table 6-16. NYISO 2002 Emergency Program Participants

Year	EDRP Only	EDRP & SCR	SCR Only	Total
2001	217	116	94	427
2002	1534	177	74	1785

Table 6-17. Average Zonal and Total Effects of EDRP Events on NYISO Electricity Markets, April 2002

		Simulated Without EDRP		With EDRP Load Reduction					
Zone	DAM FBL	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP (MW)	LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
New York City									
Hourly Avg.	5,451		223	22.2	215	-0.26%	-3.42%	13.2	24,453
Total	65,416			266.4					293,433
% of G. Total	54%			61%					82%
Long Island									
Hourly Avg.	3,169		215	6.1	209	-0.19%	-2.18%	11.8	948
Total	38,026			73.7					11,370
% of G. Total	31%			17%					3%
Hudson Region									
Hourly Avg.	1,551	2,922	191	7.8	187	-0.26%	-1.63%	6.2	4,506
Total	18,611	35,067		93.3					54,071
% of G. Total	15%	20%		22%					15%
Average				**36.1**					
Grand Total	**122,053**	**177,092**		**433.4**					**358,874**

Table 6-18. NYISO 2002 Emergency Program Participant Statistics by Superzone

	Participant Count				Subscribed MWs				
	EDRP	SCR	Joint		EDRP	SCR	Joint EDRP & SCR		
Superzone	Only	Only	EDRP & SCR	Total	Only	Only	SCR	EDRP	Total
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Western NY	411	23	85	519	541	54	422	385	1,402
Capital	47	3	9	59	53	2	68	51	174
Hudson River	47	2	19	68	49	0	13	19	81
NYC	107	35	32	174	116	27	82	61	286
Long Island	922	11	32	965	191	7	5	13	216
Total	1534	74	177	1785	950	91	591	529	2,160

Note: These superzones are aggregations of the NYISO pricing zones, as follows:
Western NY = pricing zones A, B, C, D, and E.
Capital = pricing zone F.
Hudson River = pricing zones G, H, and I.
NYC = pricing zone J.
Long Island = pricing zone I.
Note: na = not applicable; N/A = not available.

Table 6-19. Average Zonal and Total Effects of EDRP Events on NYISO Electricity Markets, Summer 2002

		Simulated w/o EDRP		Simulated w/ EDRP					
Zone	DAM FBL	Real-Time Load (MW)	Real-Time LBMP ($/MW)	EDRP Perf (MW)	LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Capital									
Hourly Avg.	1,840	2,052	114	64.6	93	-3.15%	-20.05%	6.2	2,926
Total	18,401	20,518		645.6					29,264
% of G. Total	8%	7%		10%					5%
New York City									
Hourly Avg.	6,321		107	86.2	99	-0.84%	-7.36%	8.8	30,576
Total	63,205			861.7					305,761
% of G. Total	27%			13%					53%
Long Island									
Hourly Avg.	4,488		177	75.4	161	-1.53%	-8.92%	5.9	6,760
Total	44,881			754.4					67,604
% of G. Total	19%			11%					12%
Western Region									
Hourly Avg.	8,306	9,237	74	406.6	54	-4.41%	-25.09%	5.8	11,973
Total	83,057	92,368		4,065.9					119,728
% of G. Total	35%	30%		61%					21%
Hudson Region									
Hourly Avg.	2,445	3,806	92	30.5	87	-0.80%	-4.39%	5.4	5,562
Total	24,452	38,060		304.6					55,622
% of G. Total	10%	13%		5%					10%
Grand Total	**233,996**	**303,125**		**6,632**					**577,979**

Table 6-20 EDRP Program Payments on New York Electricity Markets, April 2002

	EDRP Program Payments		
Zone or Region	Hourly Avg.	Total	% of G. Total
Western NY	$1,243	$7,461	3.4%
Hudson River	$6,658	$46,605	21.5%
New York City	$17,949	$125,646	58.0%
Long Island	$5,267	$36,871	17.0%
Total		$216,583	

Table 6-21 Effect of EDRP on the Average Level and Variability of Real-Time LBMPs (April, 2002)*

Zone or Region	RT-LBMP ($/MW) (w/o EDRP) Mean	Std. Dev.	Coef. of Var.**	RT-LBMP ($/MW) (w/ SCR & EDRP) Mean	Std. Dev.	Coef. of Var.**	Reduction in Mean LBMPs ($/MW)	Estimated Long-Term *Reduction* in Cost of Hedging Load#
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
New York City	$52.80	52.00	0.98	$52.53	50.92	0.97	$0.27	$181,066
Long Island	$57.43	47.68	0.83	$57.25	46.87	0.82	$0.18	$58,046
Hudson River Region	$49.01	42.18	0.86	$48.90	41.72	0.85	$0.11	$21,667
Total								**$260,780**

* Hourly averages are for April week days, hours 6:00 a.m. through 10:00 p.m.

** The coefficient of variation is a measure of relative variability. It is the standard deviation divided by the mean.

This value is the difference in mean RT-LBMP times the average amount of load scheduled in the DAM that is purchased under bilaterial contracts. There are no data for the portion of fixed bid load settled under bilaterials by zone, but it is thought to be about 40% system wide.

Table 6-22. EDRP Program Payments on New York Electricity Markets, Summer 2002

Zone	Program Payments ($)	Zone	Program Payments ($)
Capital		**Western New York**	
Hourly Avg.	32,279	Hourly Avg.	203,450
Total	322,787	Total	2,034,502
% of G. Total	10%	% of G. Total	61%
New York		**Hudson Region**	
Hourly Avg.	43,161	Hourly Avg.	15,228
Total	431,606	Total	152,281
% of G. Total	13%	% of G. Total	5%
Long Island			
Hourly Avg.	37,720		
Total	377,205	**Grand Total**	**3,318,381**
% of G. Total	11%		

Table 6-23 Effect of EDRP on the Average Level and Variability of Real-Time LBMPs (Summer, 2002)*

Zone or Region	RT-LBMP ($/MW) (w/o EDRP)			RT-LBMP ($/MW) (w/ EDRP)			Overall Reduction in Mean LBMPs ($/MW)	Estimated Long-Term *Reduction* in Cost of Hedging Load#
	Mean	Standard Deviation	Coefficient of Variation**	Mean	Standard Deviation	Coefficient of Variation**		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
Capital	$45.48	54.68	1.20	$45.28	54.47	1.20	$0.20	$39,925
New York City	$66.71	60.36	0.90	$66.64	60.31	0.91	$0.08	$62,272
Long Island	$75.42	65.75	0.87	$75.26	65.52	0.87	$0.15	$72,138
Western NY	$41.32	52.65	1.27	$41.13	52.55	1.28	$0.19	$184,426
Hudson River Region	$49.54	59.58	1.20	$49.50	59.53	1.20	$0.04	$11,471
Total								**$330,307**

* Hourly averages are for week days, hours 6:00 a.m. through 10:00 p.m.

** The coefficient of variation is a measure of relative variability. It is the standard deviation divided by the mean.

This value is the difference in mean RT-LBMP times the average amount of load scheduled in the DAM that is purchased under bilaterial contracts. There are no data for the portion of fixed bid load settled under bilaterial by zone, but it is thought to be about 40% system wide. There are 352 hours in April week days from 6:00 a.m. through 10:00 p.m.

Table 6-24. April 2002 % Load At Risk to Equate VEUE and Program Payments

Reduction in LOLP	Outage Cost			
	$1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	(a)	(b)	(c)	(d)
0.05	3.6%	2.4%	1.4%	0.7%
0.10	1.8%	1.2%	0.7%	0.4%
0.15	1.2%	0.8%	0.5%	0.2%
0.20	0.9%	0.6%	0.4%	0.2%
0.25	0.7%	0.5%	0.3%	0.1%
0.50	0.4%	0.2%	0.1%	0.1%

Note: Calculated using equation (25). For any combination of reduction in LOLP and outage cost, program benefits outweigh costs for % loads at risk higher than those reported in each cell of the table.

Table 6-25. Summer 2002 % Load At Risk to Equate VEUE and Program Payments

Reduction in LOLP	Outage Cost			
	$1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	(a)	(b)	(c)	(d)
0.05	48.9%	32.6%	19.6%	9.8%
0.10	24.4%	16.3%	9.8%	4.9%
0.15	16.3%	10.9%	6.5%	3.3%
0.20	12.2%	8.1%	4.9%	2.4%
0.25	9.8%	6.5%	3.9%	2.0%
0.50	4.9%	3.3%	2.0%	1.0%

Note: Calculated using equation (25). For any combination of reduction in LOLP and outage cost, program benefits outweigh costs for % loads at risk higher than those reported in each cell of the table.

Table 6-26. Average Zonal and Total Effects of DADRP Scheduled Bids on New York Electricity Markets, Summer, 2002

Zone	Load in in RTM	With DADRP Day-Ahead Load (MW)	With DADRP Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Without DADRP Day-Ahead Load (MW)	Without DADRP Day-Ahead LBMP ($/MW)	% Change in Due to DADRP Load	% Change in Due to DADRP LBMP	Arc Price Flexibility*	Program Payments ($)#	Collateral Benefits ($)** Total	Collateral Benefits ($)** Net
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
Capital												
Hourly Avg.	1,733	1,553	70.2	7	1,559	71.2	0.4%	1.1%	3.0	521	1,696	1,018
Total	273,842	245,322		1,046	246,368					82,317	267,963	160,778
% of G. Total	35%	35%		71%	35%					75%	68%	68%
Western New York												
Hourly Avg.	8,464	7,591	74	7	7,598	74	0.1%	0.4%	4.7	473	2,146	1,288
Total	499,382	447,847		422	448,269					27,899	126,611	75,967
% of G. Total	65%	65%		29%	65%					25%	32%	32%
Grand Total	773,224	693,169		1,468	694,637					110,216	394,574	236,745

*As with most mathematical relations of this kind, the supply price flexibilities in the tables above are only vaild for small changes in load. Here the supply models are calibrated to the observed prices, and in mathematical terms, the load response was large. The average "arc" flexibilities only approximate the averages from the tables.

The effects in this table are based on bids accepted in the DAM. At this writing, we had no data on actual performance. Also, the program payments are based on LBMPs in the DAM. There was no way we could account for the start-up or outage cost portion of customers' bids.

**The collateral benefits are equal to the difference in actual and simulated LBMP multiplied by load served. The net collateral benefits are estimated to be 0.6 of the total collateral benefits. This assumes that an average of 40% of load is purchased through bilaterals. Thus, this net amount is the savings to customers buying load in the DAM.

Table 6-27. DADRP Program Payments from New York Electricity Markets, Summer, 2002

Zone	Program Payments ($)#	Zone	Program Payments ($)#
Capital		**Western New York**	
Hourly Avg.	521	Hourly Avg.	473
Total	82,317	Total	27,899
% of G. Total	75%	% of G. Total	25%

Grand Total	**110,216**

The effects in this table are based on bids accepted in the DAM. At this writing, we had no data on actual performance. Also, the program payments are based on LBMPs in the DAM. There was no way we could account for the start-up or outage cost portion of customers' bids, although the preliminary analysis of the data by the NYISO suggests that our cost estimates would increase by about 30%

Fig. 6-1: Estimated Price Flexibility Zones

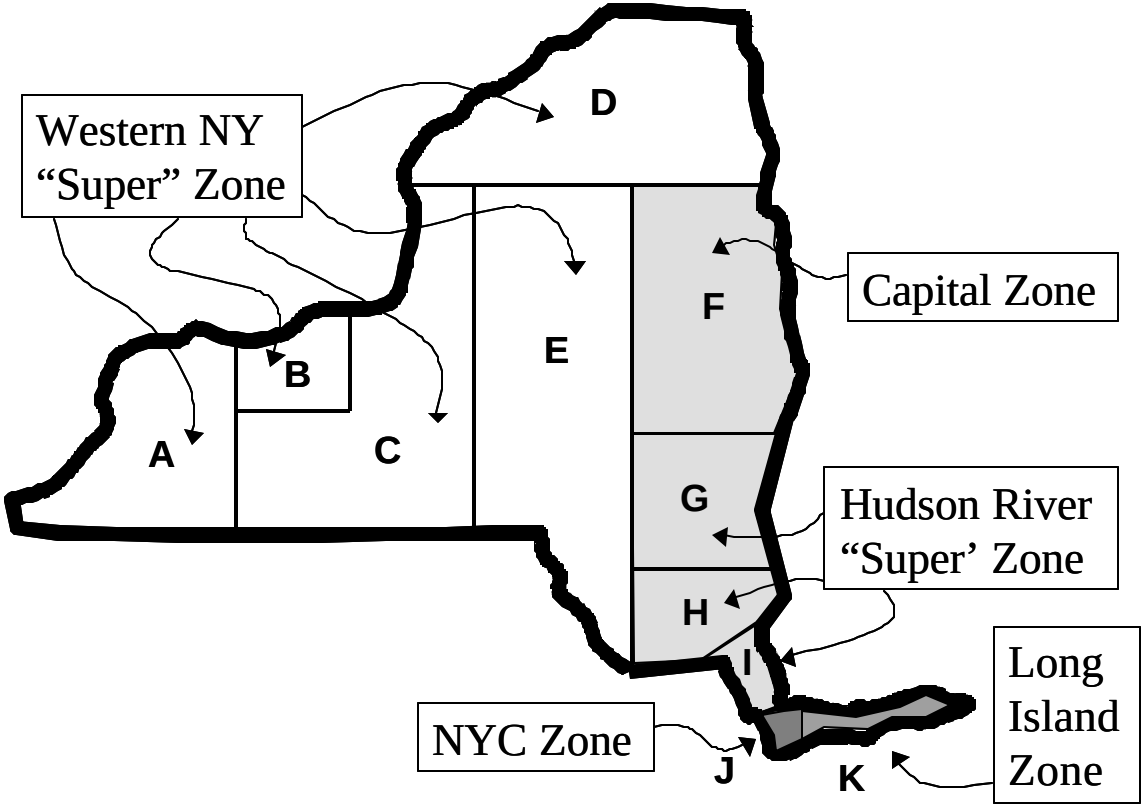


Fig. 6-2. Scatter Diagram of LBMP vs. Load

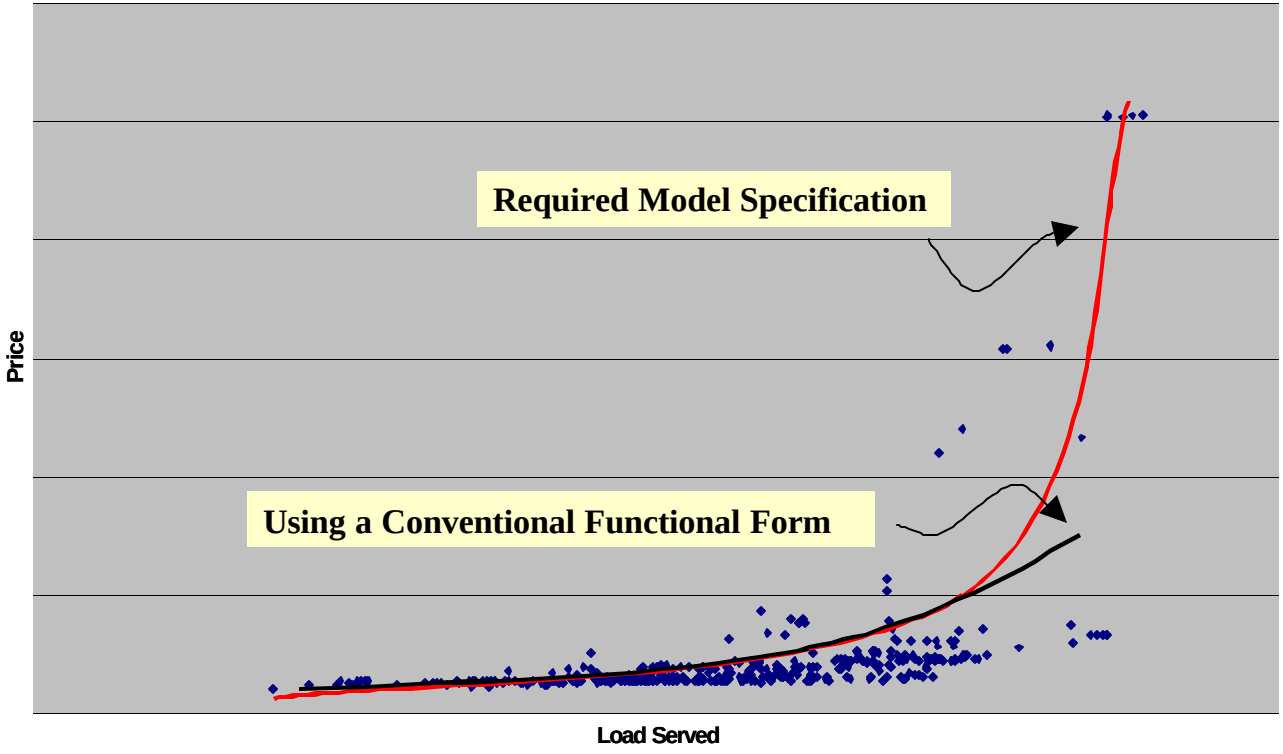


Fig. 6-3. Different Supply Regimes

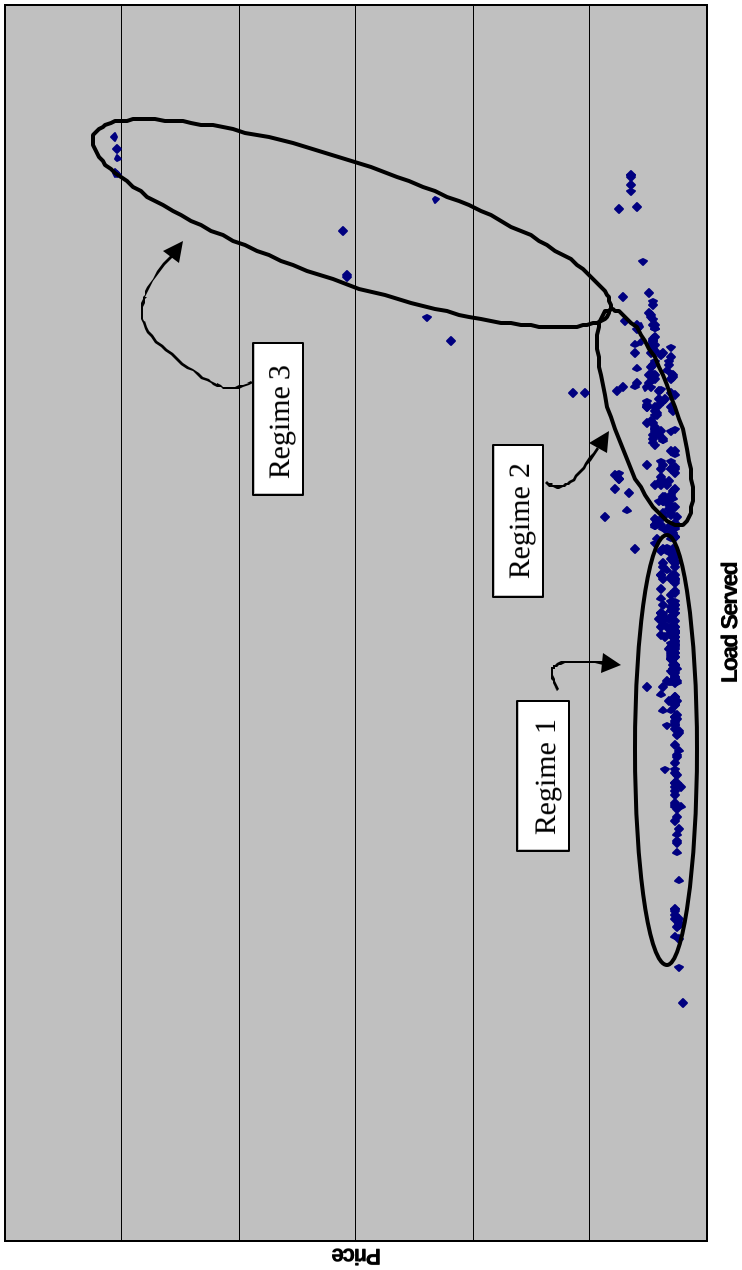


Fig. 6-4. “Spline” Model Specification

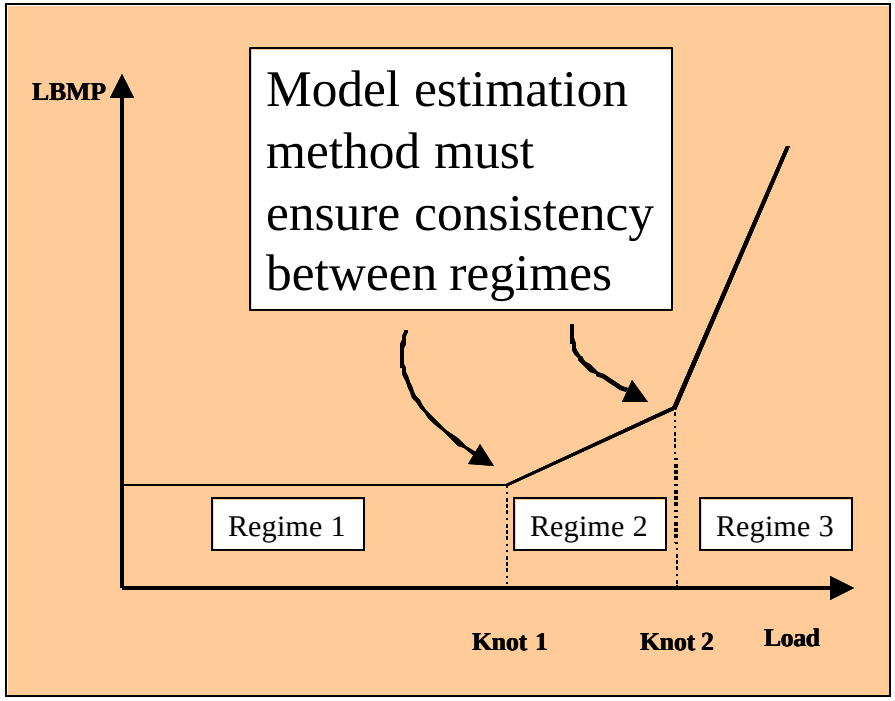


Fig. 6-5. Modeling Apparent Outliers

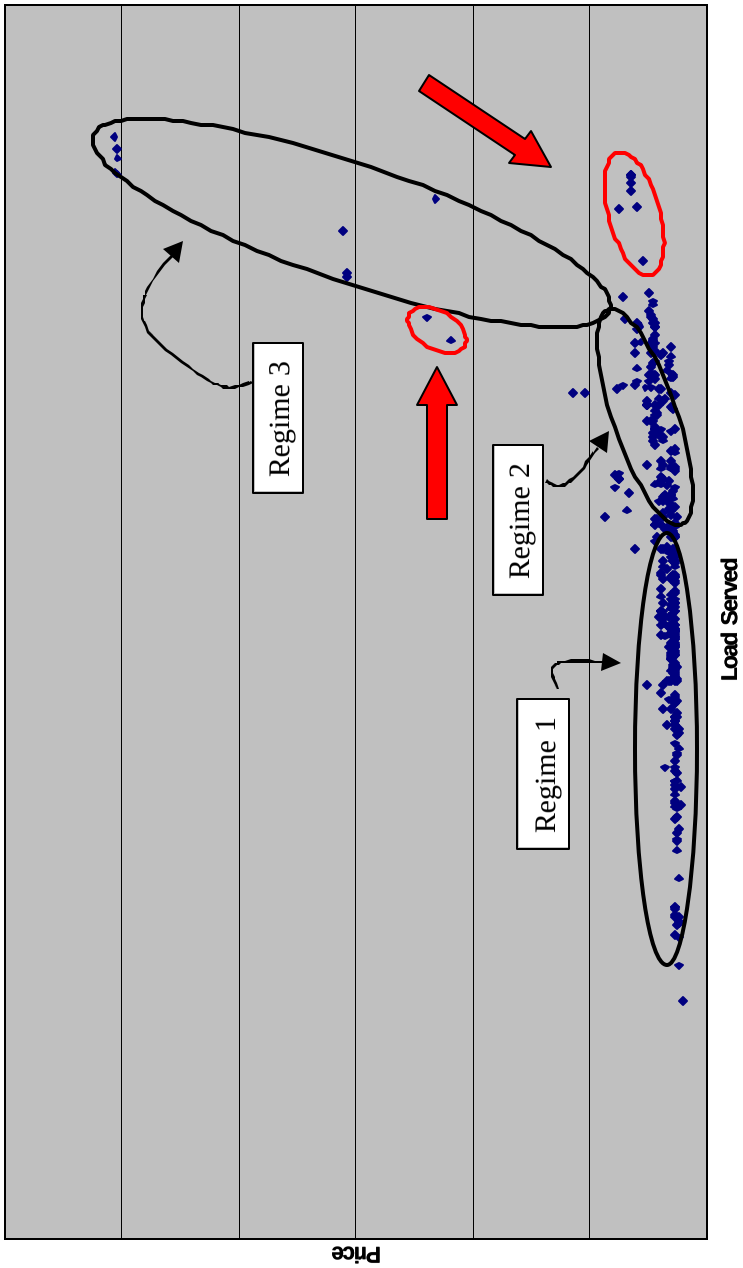
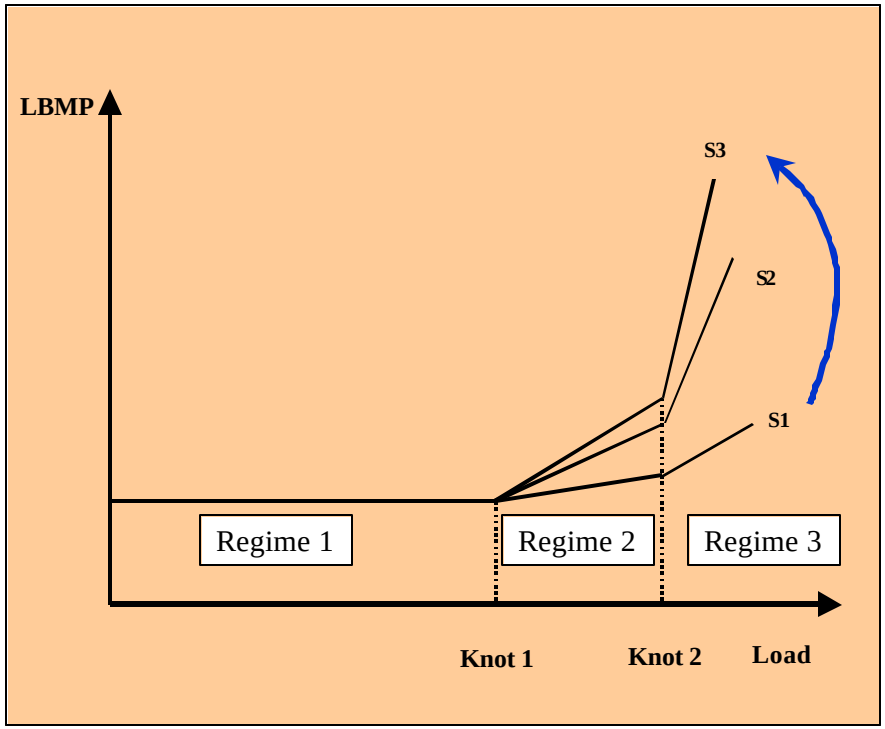


Fig. 6-6. Final Model Specification



Supply Shift due to:

- Transmission Constraints,
- Generator Availability,
- Demand in Adjacent Zones,
- Others

Fig. 6-7. Simulation of Effects of PRL Reduction

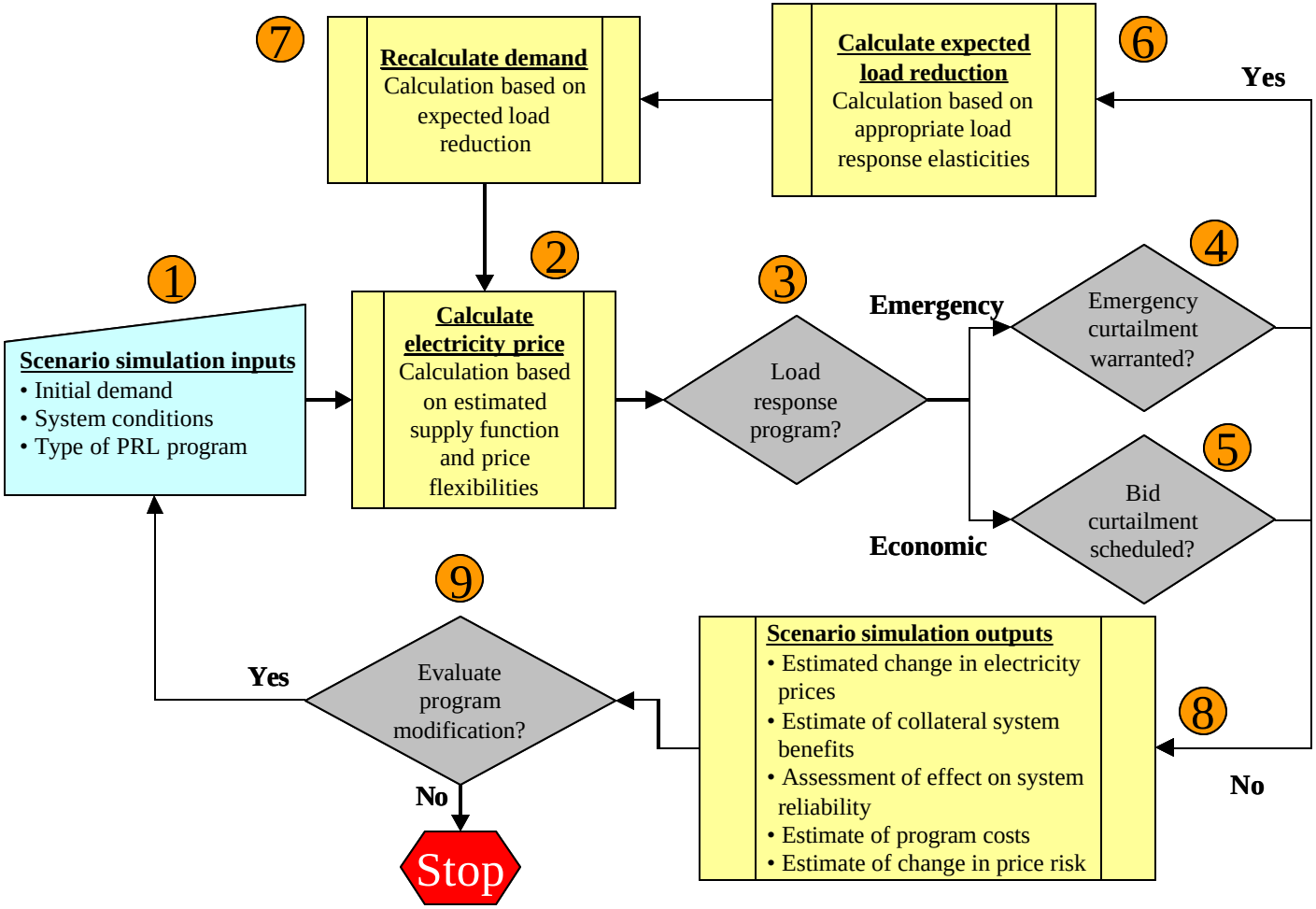


Fig. 6-8. EDRP Value of Expected Un-served Energy

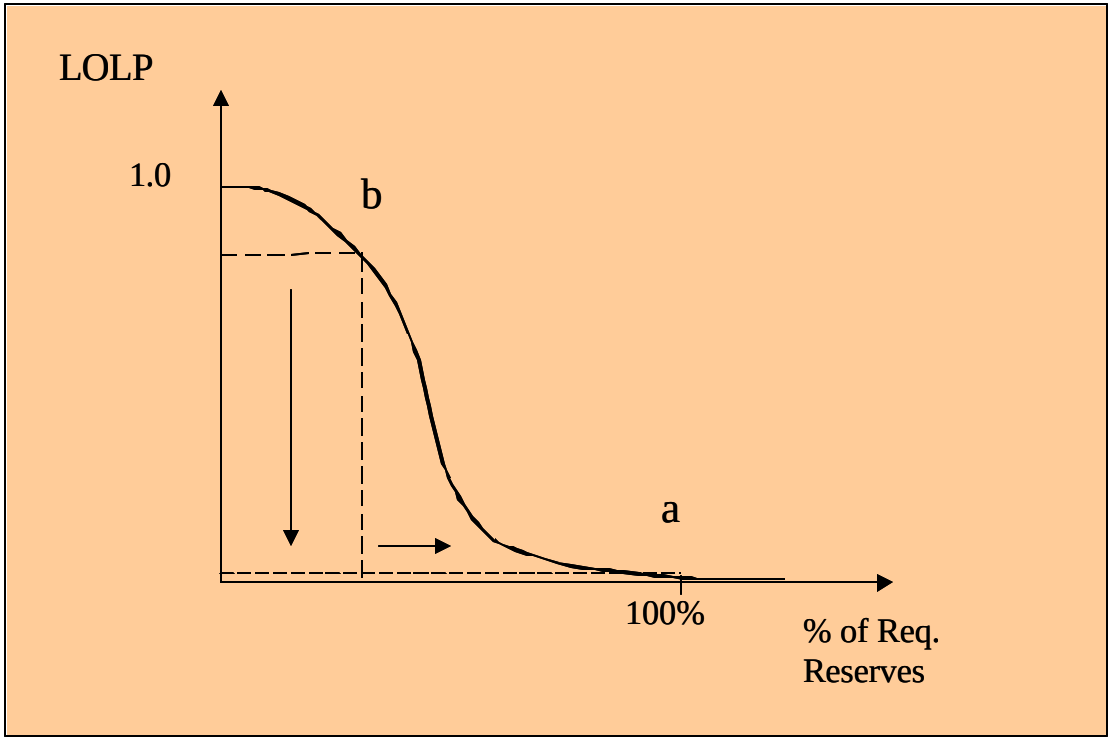


Fig. 6-9. EDRP Event Needed Reserves vs. EDRP Load Response

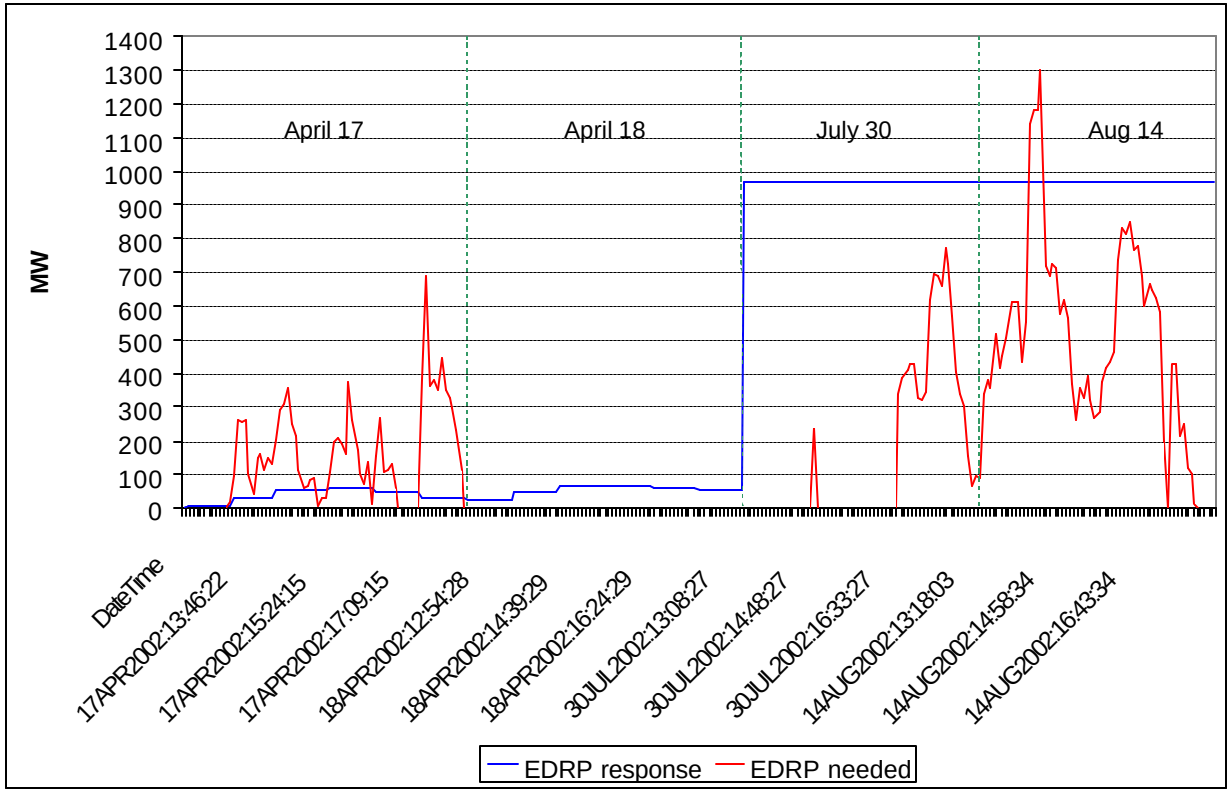


Fig. 6-1A. Hudson River Real-Time Market Estimated Supply Curve for April 2002

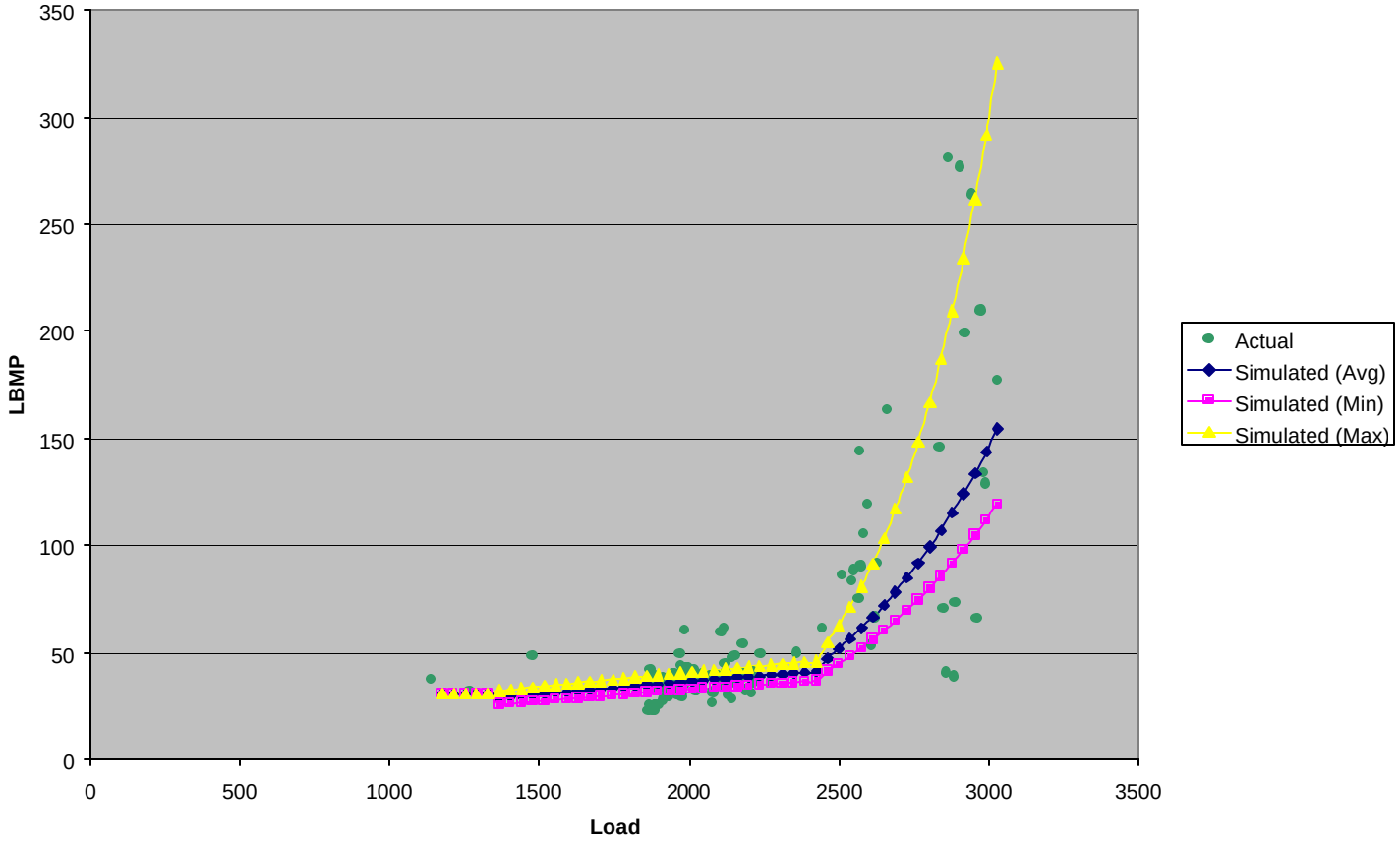


Fig. 6-2A. New York City Real-Time Market Estimated Supply Curve for April 2002

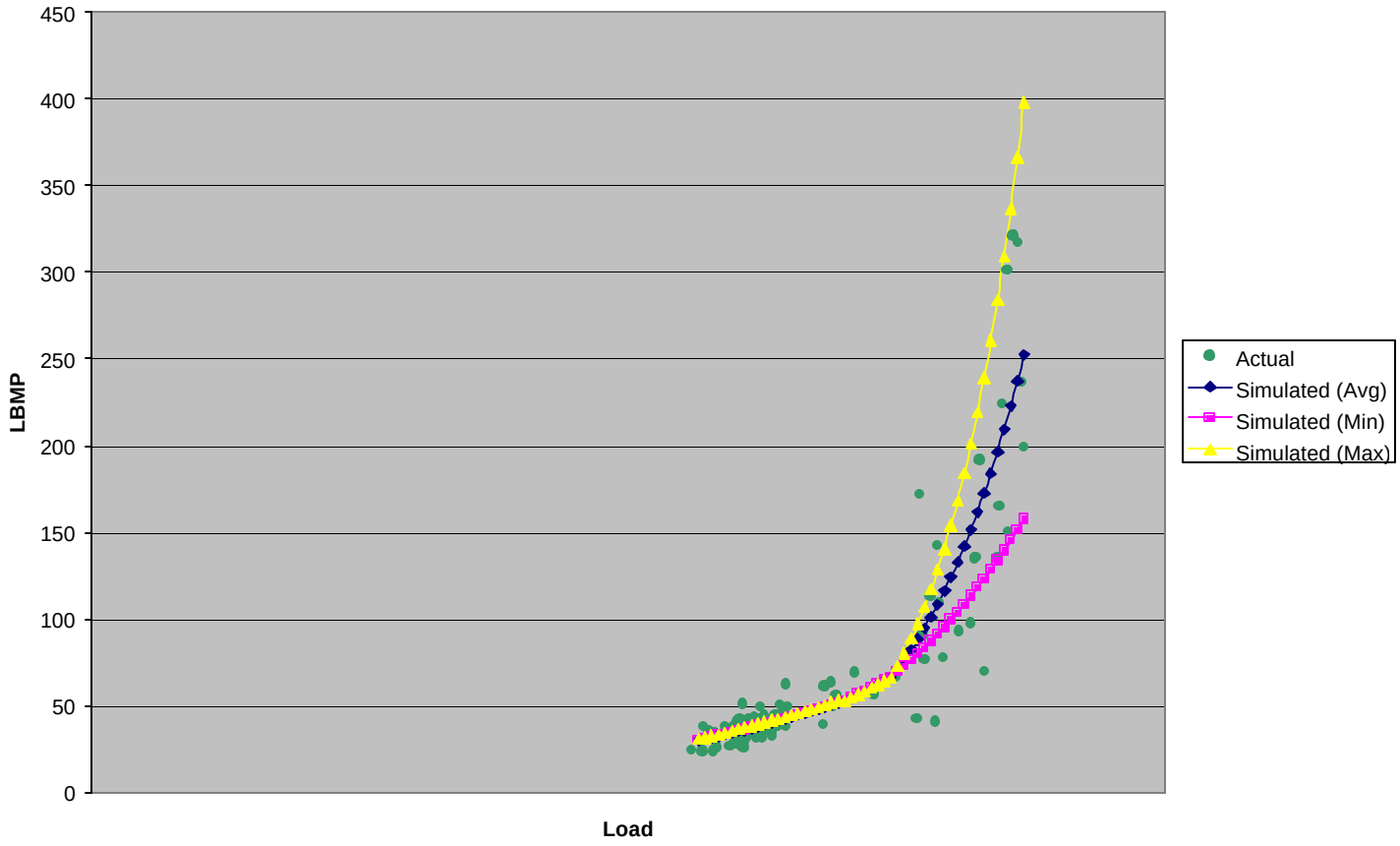


Fig. 6-3A. Long Island Real-Time Market Estimated Supply Curve for April 2002

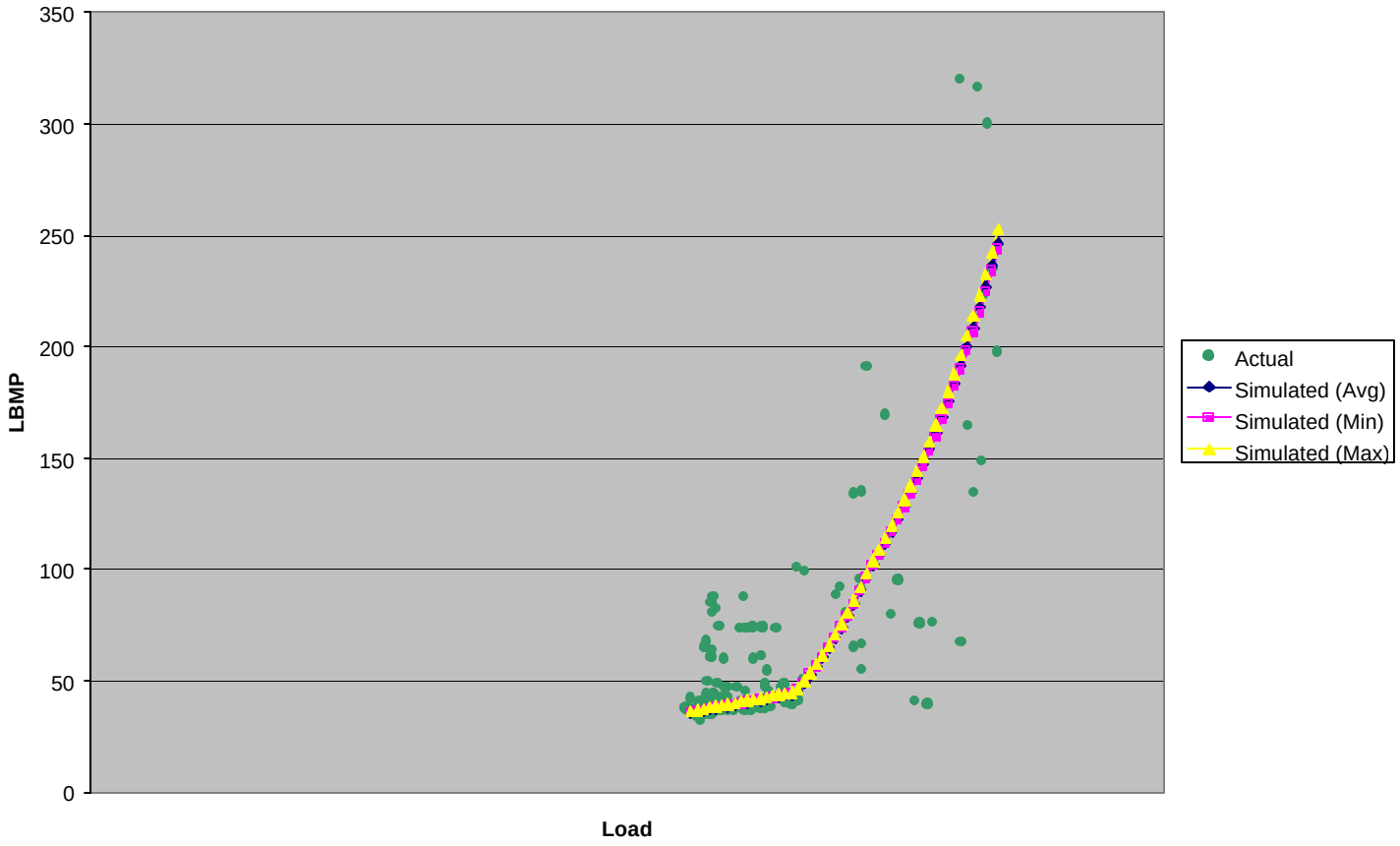


Fig. 6-4A. Western NY Real-Time Market Estimated Supply Curves for Summer 2002

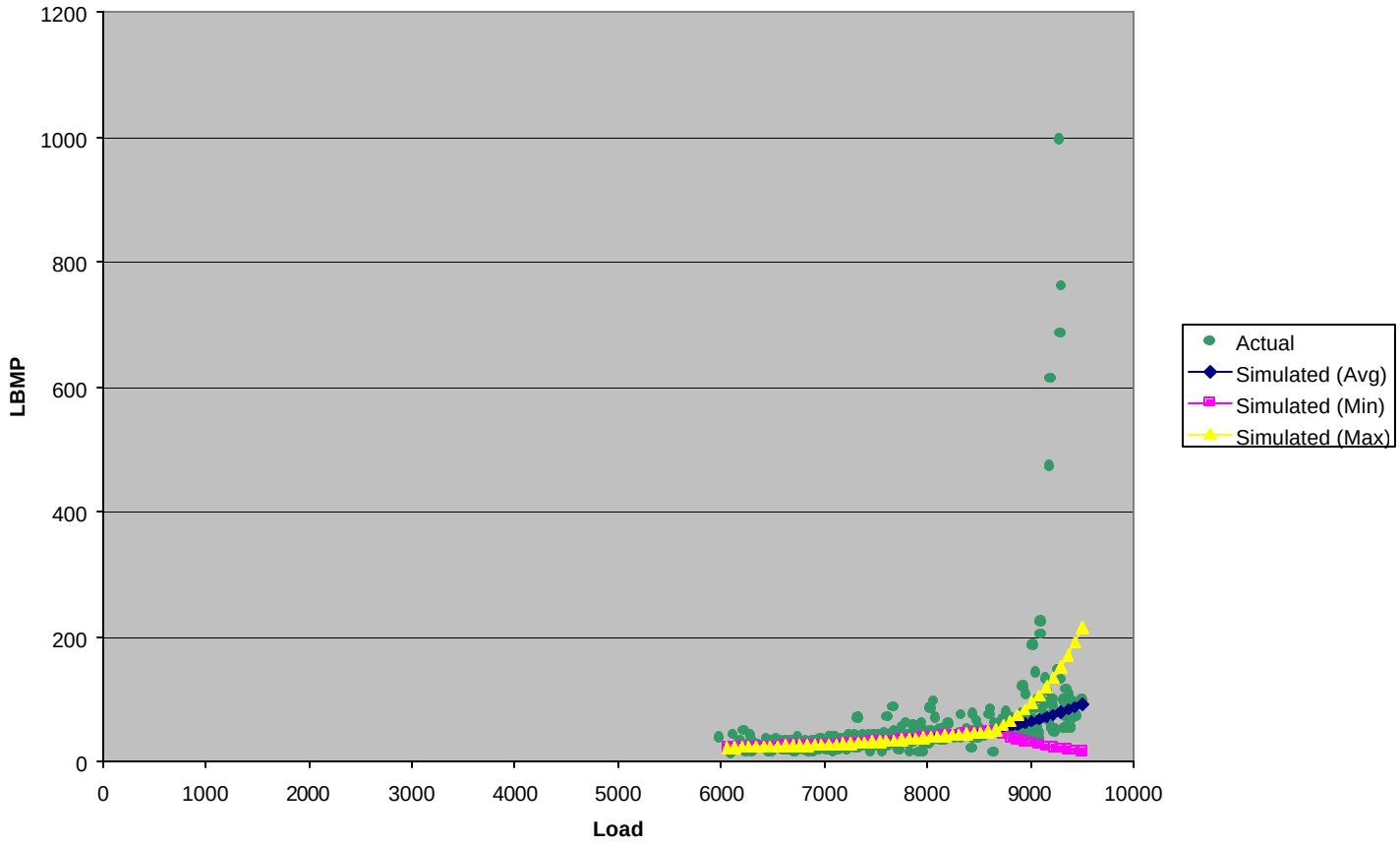


Fig. 6-5A. Capital Real-Time Market Estimated Supply Curve for Summer 2002

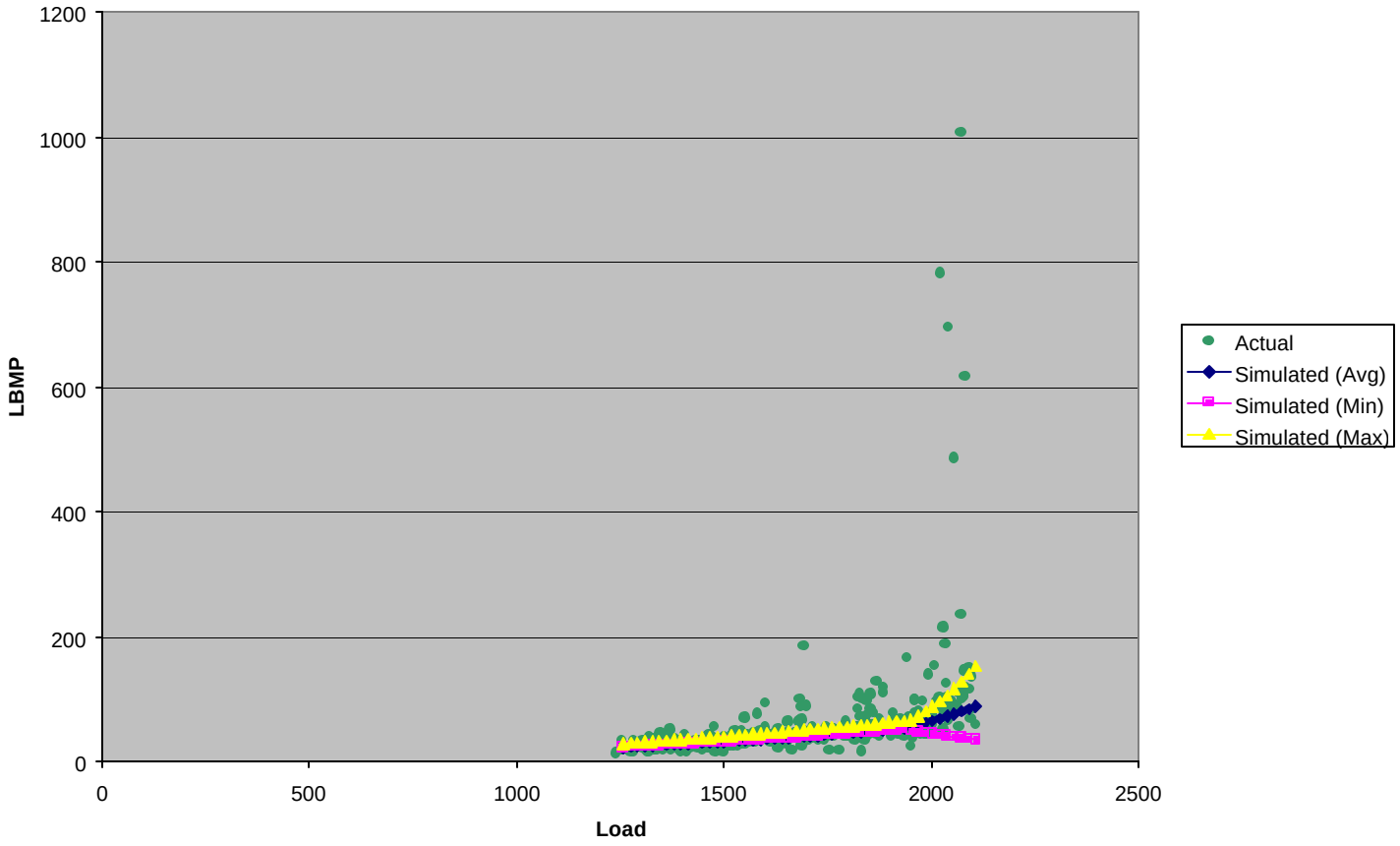


Fig. 6-6A. Hudson River Real-Time Market Estimated Supply Curve for Summer 2002

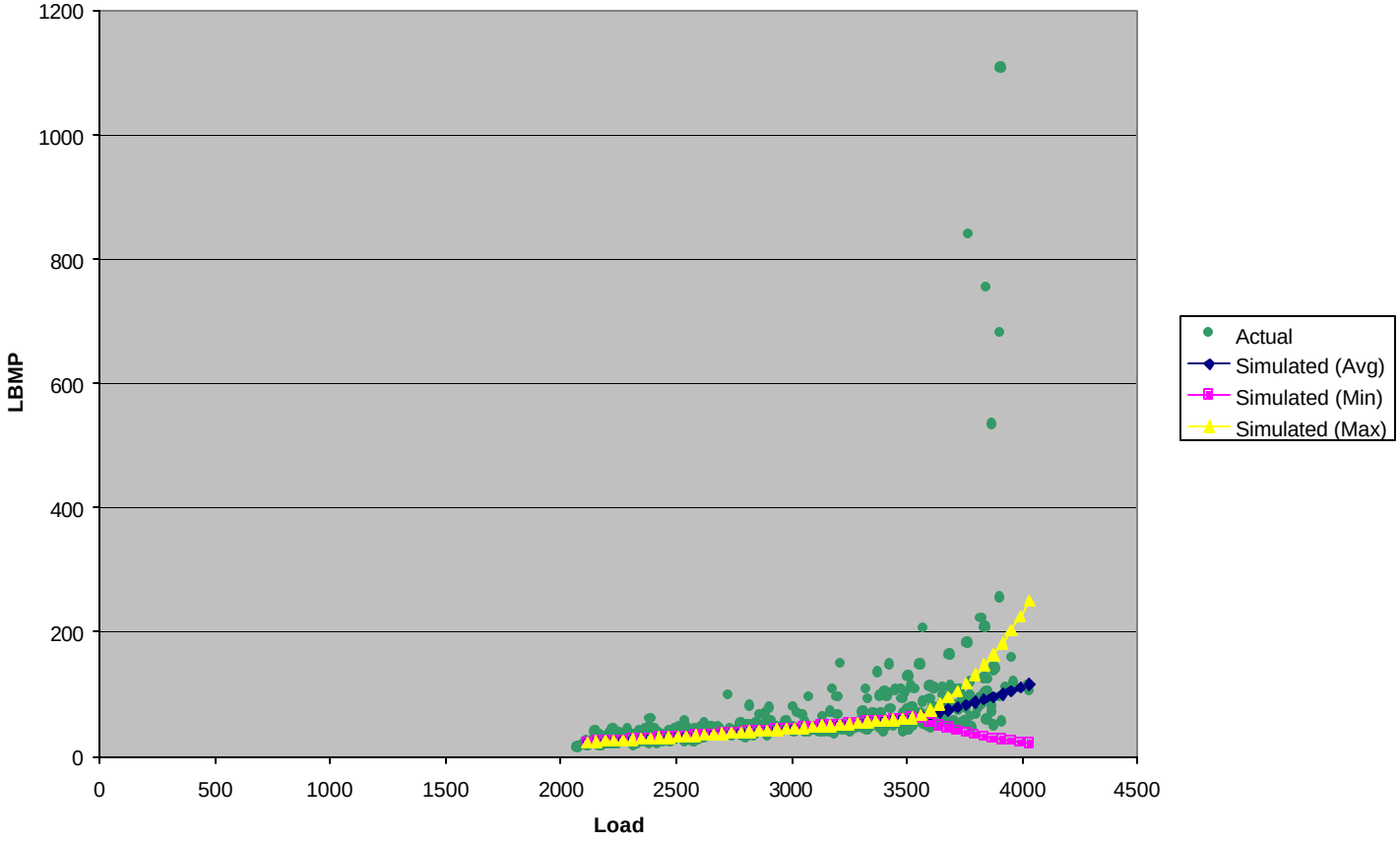


Fig. 6-7A. New York City Real-Time Market Estimated Supply Curve for Summer 2002

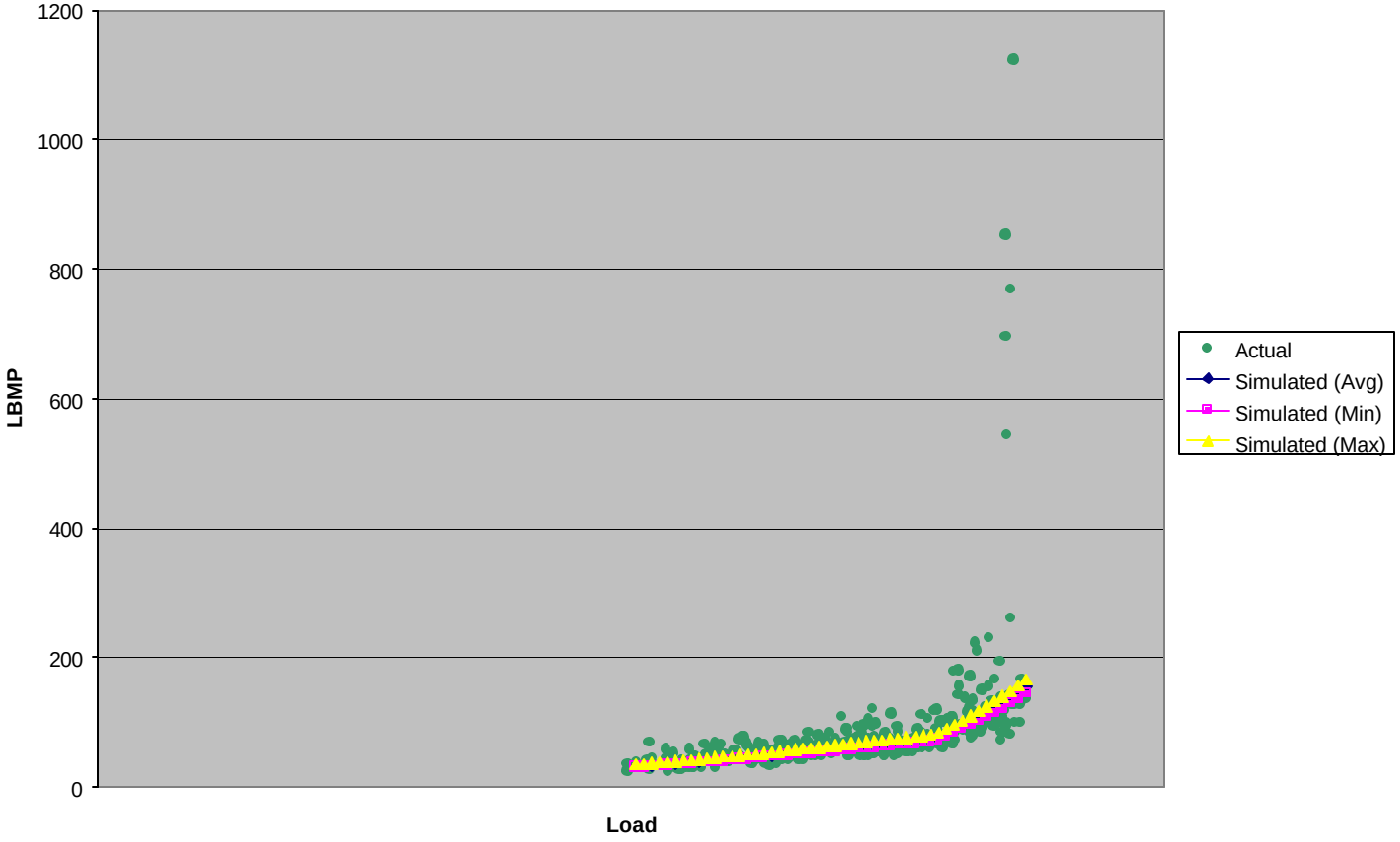


Fig. 6-8A. Long Island Real-Time Market Estimated Supply Curve for Summer 2002

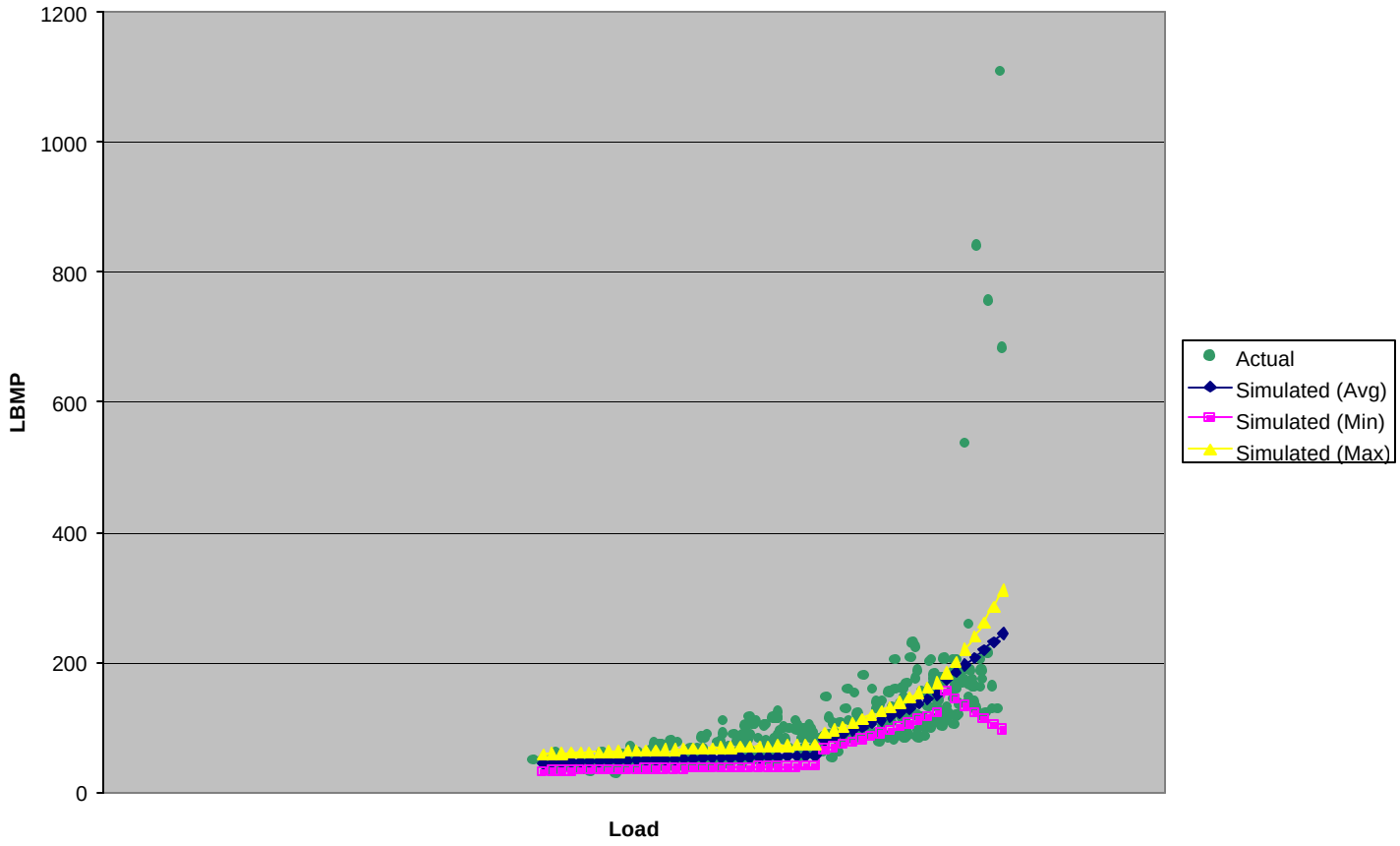


Fig. 6-9A. Western NY Day-Ahead Market Estimated Supply Curves for Summer 2002

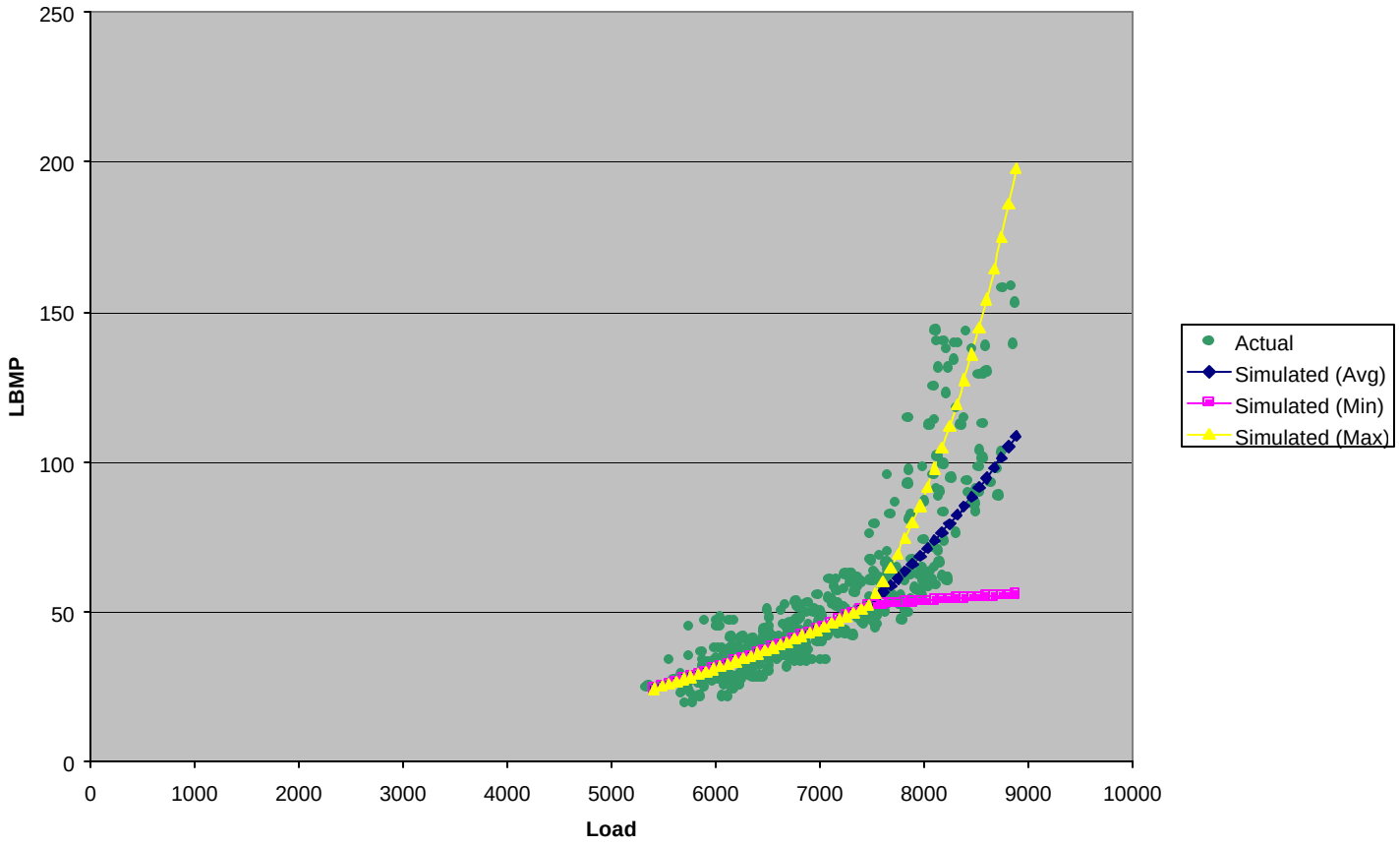


Fig. 6-10A. Capital Day-Ahead Market Estimated Supply Curve for Summer 2002

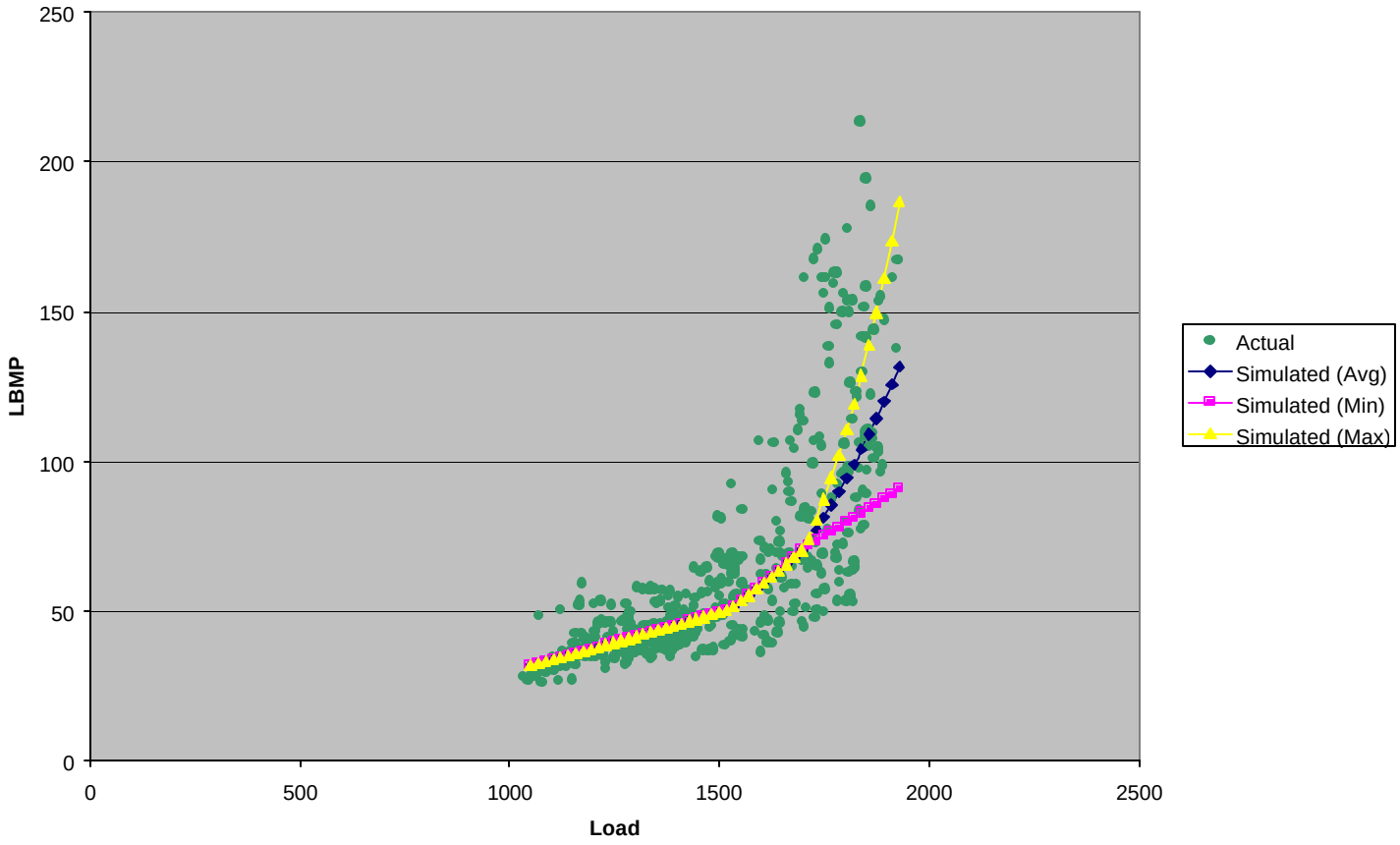


Fig. 6-11A. Hudson River Day-Ahead Market Estimated Supply Curve for Summer 2002

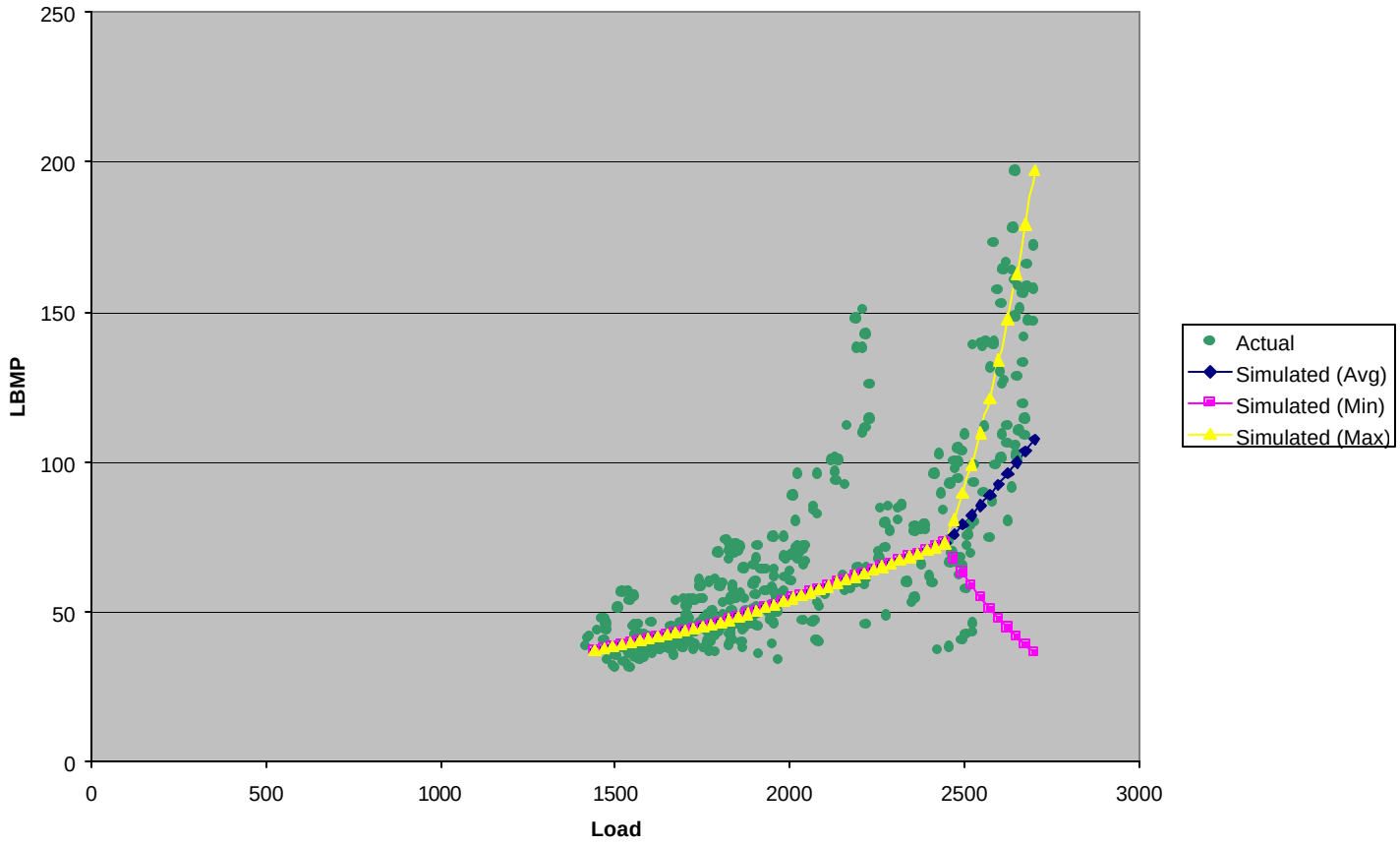


Fig. 6-12A. New York City Day-Ahead Market Estimated Supply Curve for Summer 2002

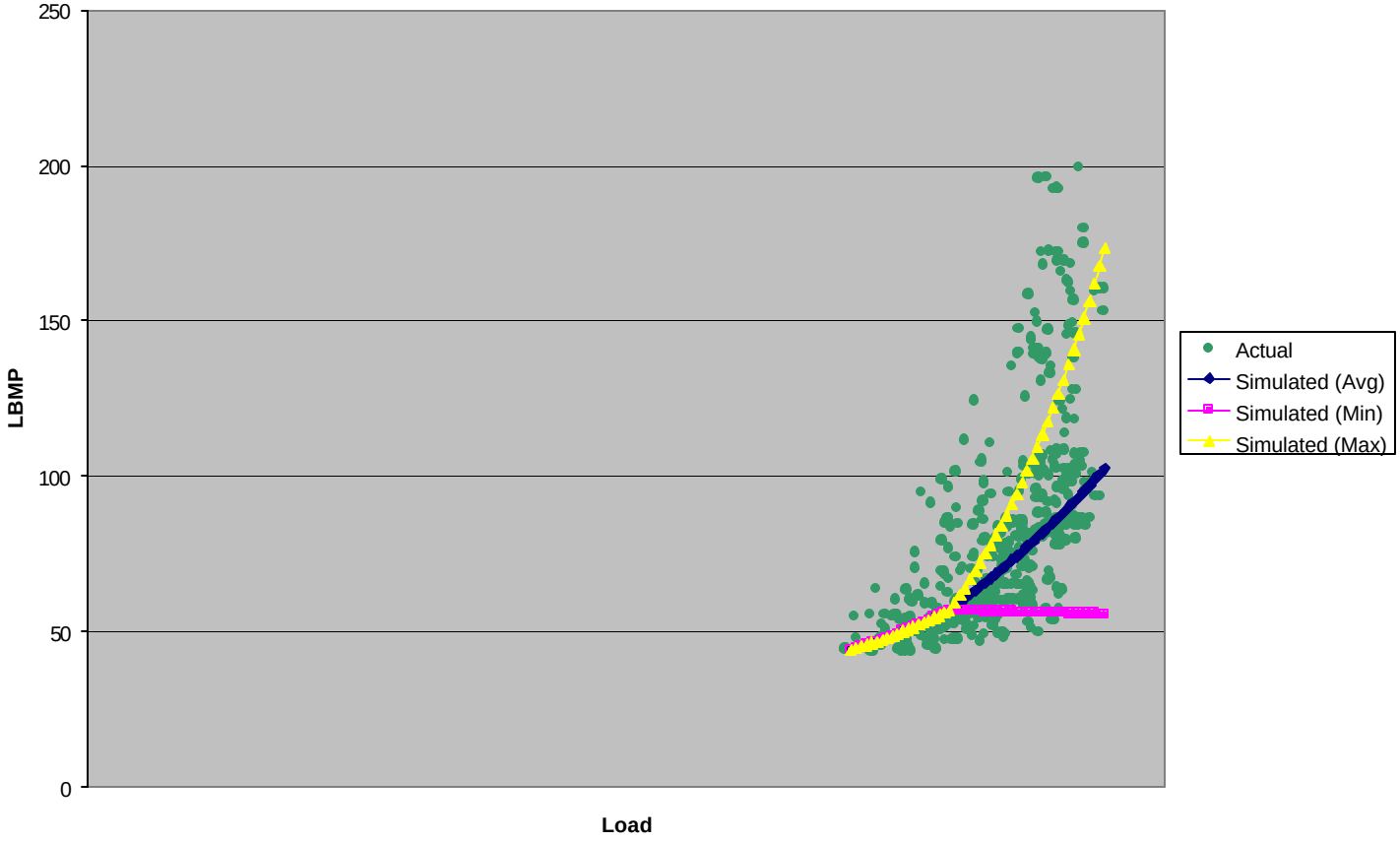


Fig. 6-13A. Long Island Day-Ahead Market Estimated Supply Curve for Summer 2002

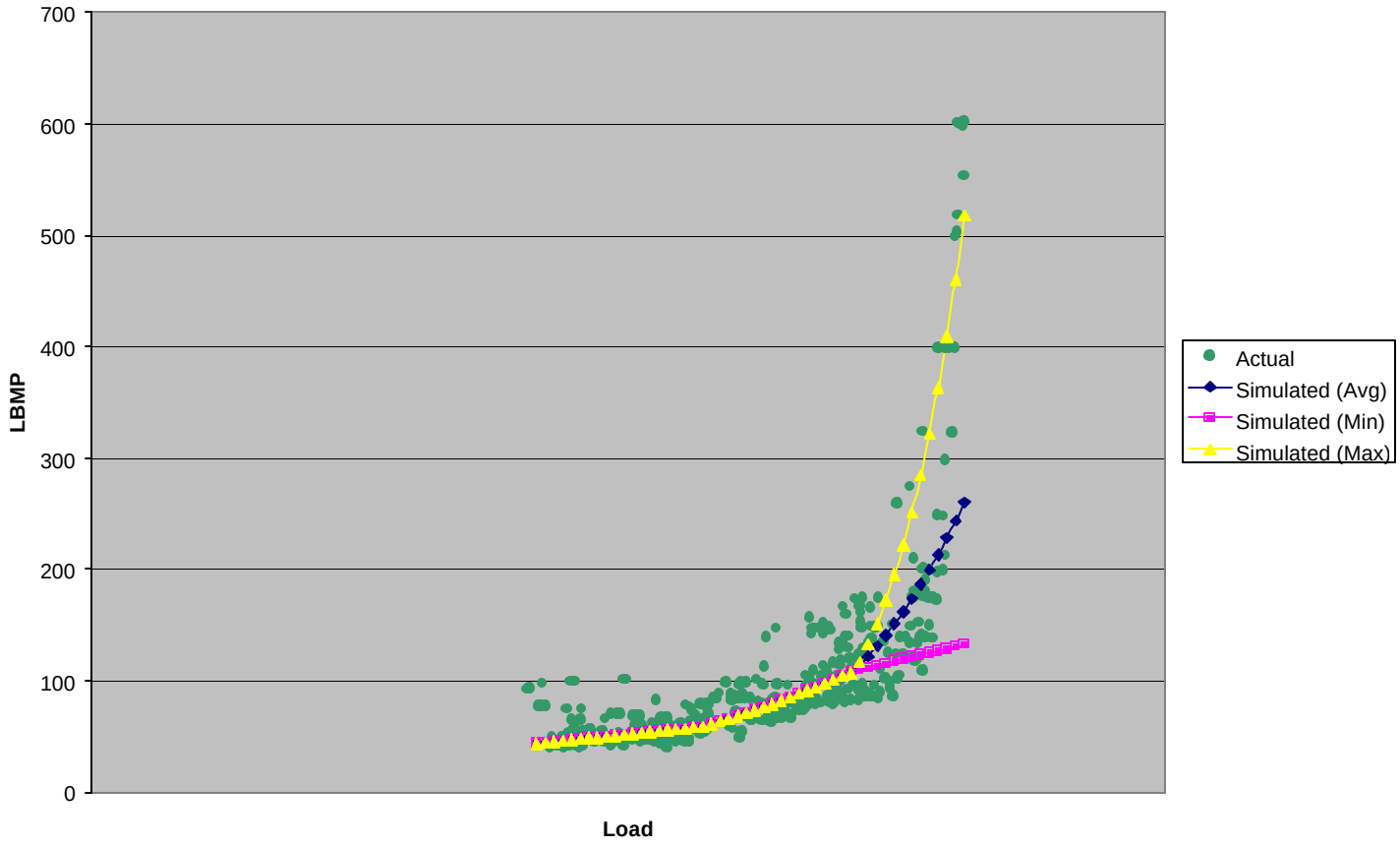


Table 6-1B. Daily Effect of EDRP Events in the New York City Zone, April 2002

			Simulated w/o EDRP			Simulated w/ EDRP					
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load	Real-Time LBMP	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
4/17/02	12	5,449		90		6		89	-0.1%	-1.0%	14	2,655
4/17/02	13	5,471		171		22		165	-0.3%	-3.5%	13	17,643
4/17/02	14	5,457		233		25		224	-0.3%	-4.0%	13	27,849
4/17/02	15	5,485		313		26		301	-0.3%	-4.0%	13	38,333
4/17/02	16	5,451		155		25		150	-0.3%	-3.6%	12	17,196
4/17/02	17	5,359		71		19		69	-0.2%	-2.7%	12	5,688
4/18/02	12	5,491		386		9		380	-0.1%	-1.4%	14	16,800
4/18/02	13	5,510		333		23		321	-0.3%	-3.6%	14	36,684
4/18/02	14	5,491		332		29		317	-0.3%	-4.7%	14	48,714
4/18/02	15	5,467		247		29		236	-0.3%	-4.6%	14	36,842
4/18/02	16	5,436		207		29		199	-0.3%	-4.3%	13	28,676
4/18/02	17	5,349		140		25		135	-0.3%	-3.8%	13	16,351
Hourly Average		**5,451**		**223**	**#**	**22**		**215**	**-0.3%**	**-3.4%**	**13**	**24,453**
Total		**65,416**			**0**	**266**						**293,433**

Table 6-2B. Daily Effect of EDRP Events in the Long Island Zone, April 2002

			Simulated w/o EDRP			Simulated w/ EDRP					
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load	Real-Time LBMP	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
4/17/02	12	3,210		89		0		88	0.0%	-0.1%	12	-2
4/17/02	13	3,281		165		2		164	0.0%	-0.6%	12	-11
4/17/02	14	3,333		230		9		223	-0.3%	-3.1%	12	-50
4/17/02	15	3,373		310		10		300	-0.3%	-3.4%	12	-324
4/17/02	16	3,416		151		5		149	-0.1%	-1.6%	12	-233
4/17/02	17	3,339		68		2		67	-0.1%	-0.9%	12	-56
4/18/02	12	2,903		325		6		317	-0.2%	-2.3%	12	2159
4/18/02	13	2,968		329		8		320	-0.2%	-2.8%	12	2496
4/18/02	14	3,027		326		8		316	-0.2%	-2.8%	12	2541
4/18/02	15	3,076		242		8		235	-0.2%	-2.9%	12	1983
4/18/02	16	3,082		204		9		197	-0.3%	-3.0%	12	1816
4/18/02	17	3,018		138		8		134	-0.2%	-2.8%	12	1050
Hourly Average		**3,169**		**215**	**#**	**6**		**209**	**-0.2%**	**-2.2%**	**12**	**948**
Total		**38,026**				**74**						**11,370**

Table 6-3B. Daily Effect of EDRP Events in the Hudson River Superzone, April 2002

			Simulated w/o EDRP			Simulated w/ EDRP					
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load	Real-Time LBMP	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
4/17/02	12	1,564	2,771	80		2	2,769	80	-0.1%	-0.5%	6	486
4/17/02	13	1,603	2,843	148		7	2,836	146	-0.2%	-1.6%	7	2,954
4/17/02	14	1,608	2,931	204		9	2,922	199	-0.3%	-2.2%	7	5,822
4/17/02	15	1,598	2,954	272		10	2,944	264	-0.3%	-2.8%	8	10,280
4/17/02	16	1,590	2,992	137		9	2,983	134	-0.3%	-2.1%	7	3,996
4/17/02	17	1,578	2,968	67		5	2,963	66	-0.2%	-0.8%	5	766
4/18/02	12	1,516	2,788	289		3	2,785	286	-0.1%	-0.9%	8	3,465
4/18/02	13	1,524	2,876	285		8	2,868	281	-0.3%	-1.4%	5	5,548
4/18/02	14	1,520	2,916	281		9	2,907	277	-0.3%	-1.6%	5	6,085
4/18/02	15	1,505	2,986	214		11	2,975	210	-0.4%	-1.8%	5	5,781
4/18/02	16	1,508	3,041	180		11	3,030	177	-0.4%	-1.8%	5	5,074
4/18/02	17	1,497	3,001	131		9	2,992	129	-0.3%	-1.9%	7	3,813
Hourly Average		**1,551**	**2,922**	**191**	**#**	**8**	**2,915**	**187**	**-0.3%**	**-1.6%**	**6**	**4,506**
Total		**18,611**	**35,067**			**93**	**34,974**					**54,071**

Table 6-1C. Daily Effect of EDRP Events in the Capital Zone, Summer 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	1,851	2,019	64		65	1,954	47	-3.2%	-25.9%	8	1,698
7/30/02	14	1,865	2,025	67		69	1,956	48	-3.4%	-29.0%	9	1,779
7/30/02	15	1,855	2,042	73		72	1,970	51	-3.5%	-29.5%	8	2,479
7/30/02	16	1,829	2,042	114		71	1,971	80	-3.5%	-29.5%	8	4,784
7/30/02	17	1,798	2,026	104		63	1,963	78	-3.1%	-24.9%	8	4,270
8/14/02	13	1,826	2,110	107		57	2,053	95	-2.7%	-11.6%	4	2,825
8/14/02	14	1,841	2,142	118		61	2,081	105	-2.8%	-11.7%	4	3,328
8/14/02	15	1,845	2,154	170		61	2,093	150	-2.9%	-11.8%	4	4,980
8/14/02	16	1,851	2,006	191		62	1,944	167	-3.1%	-12.9%	4	2,297
8/14/02	17	1,840	1,952	128		65	1,887	111	-3.3%	-13.7%	4	825
Hourly Average		**1,840**	**2,052**	**114**	**#**	**65**	**1,987**	**93**	**-3.2%**	**-20.1%**	**6**	**2,926**
Total		**18,401**	**20,518**			**646**	**19,872**					**29,264**

Table 6-2C. Daily Effect of EDRP Events in the New York City Zone, Summer 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	6,326		78		86		72	-0.8%	-7.9%	9	23,721
7/30/02	14	6,319		91		92		84	-0.9%	-7.8%	9	27,253
7/30/02	15	6,301		92		93		85	-0.9%	-7.1%	8	25,613
7/30/02	16	6,256		105		94		98	-0.9%	-6.5%	7	26,848
7/30/02	17	6,123		99		87		93	-0.9%	-6.4%	7	25,038
8/14/02	13	6,431		102		77		95	-0.7%	-7.1%	10	27,779
8/14/02	14	6,427		106		82		98	-0.8%	-7.1%	9	29,335
8/14/02	15	6,415		136		82		126	-0.8%	-7.0%	9	36,982
8/14/02	16	6,369		153		85		142	-0.8%	-7.6%	9	45,634
8/14/02	17	6,238		108		85		98	-0.8%	-9.2%	11	37,557
Hourly Average		**6,321**		**107**	**#**	**86**		**99**	**-0.8%**	**-7.4%**	**9**	**30,576**
Total		**63,205**				**862**						**305,761**

Table 6-3C. Daily Effect of EDRP Events in the Long Island Zone, Summer 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	4,094		206		71		186	-1.5%	-9.4%	6	14002
7/30/02	14	4,143		207		76		186	-1.5%	-9.8%	6	14421
7/30/02	15	4,193		205		73		186	-1.5%	-9.2%	6	13348
7/30/02	16	4,227		204		71		186	-1.4%	-8.7%	6	13089
7/30/02	17	4,182		205		64		187	-1.3%	-8.7%	7	13828
8/14/02	13	4,725		110		46		104	-0.9%	-5.9%	6	533
8/14/02	14	4,760		132		95		118	-1.9%	-10.9%	6	1009
8/14/02	15	4,809		151		90		136	-1.8%	-10.3%	6	421
8/14/02	16	4,875		159		86		143	-1.8%	-10.4%	6	-1091
8/14/02	17	4,873		185		82		175	-1.7%	-5.9%	3	-1954
Hourly Average		**4,488**		**177**	**#**	**75**		**161**	**-1.5%**	**-8.9%**	**6**	**6,760**
Total		**44,881**				**754**						**67,604**

Table 6-4C. Daily Effect of EDRP Events in the Western NY Superzone, Summer 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	8,176	8,942	52		385	8,557	46	-4.3%	-11.9%	3	2382
7/30/02	14	8,185	8,927	53		427	8,500	46	-4.8%	-13.2%	3	2214
7/30/02	15	8,131	8,833	57		419	8,414	50	-4.7%	-13.1%	3	2107
7/30/02	16	8,050	8,867	88		417	8,450	77	-4.7%	-13.0%	3	4579
7/30/02	17	7,863	8,736	86		404	8,332	75	-4.6%	-12.8%	3	5138
8/14/02	13	8,568	9,718	77		319	9,399	53	-3.3%	-30.5%	9	19467
8/14/02	14	8,606	9,732	90		378	9,354	54	-3.9%	-40.0%	10	26909
8/14/02	15	8,590	9,677	102		585	9,092	46	-6.0%	-55.2%	9	28396
8/14/02	16	8,530	9,577	82		373	9,204	54	-3.9%	-33.7%	9	18536
8/14/02	17	8,358	9,359	57		359	9,000	41	-3.8%	-27.5%	7	10001
Hourly Average		**8,306**	**9,237**	**74**	**#**	**407**	**8,830**	**54**	**-4.4%**	**-25.1%**	**6**	**11,973**
Total		**83,057**	**92,368**			**4,066**	**88,302**					**119,728**

Table 6-5C. Daily Effect of EDRP Events in the Hudson River Superzone, Summer 2002

			Simulated w/o EDRP			Simulated w/ EDRP						
Date	Hour	DAM FBL (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)		EDRP Perf. (MW)	Real-Time Load (MW)	Real-Time LBMP ($/MW)	% Change in Load	% Change in LBMP	Arc Price Flexibility	Transfer from Gens to LSEs ($)
7/30/02	13	2,165	3,720	53		30	3,690	52	-0.8%	-2.9%	3	2324
7/30/02	14	2,219	3,792	53		31	3,761	52	-0.8%	-2.3%	3	1892
7/30/02	15	2,229	3,782	57		31	3,751	55	-0.8%	-2.3%	3	2005
7/30/02	16	2,229	3,761	88		28	3,733	86	-0.8%	-2.1%	3	2808
7/30/02	17	2,211	3,685	84		26	3,659	83	-0.7%	-1.3%	2	1606
8/14/02	13	2,651	3,800	93		29	3,771	88	-0.8%	-6.2%	8	6466
8/14/02	14	2,684	3,874	103		34	3,840	96	-0.9%	-7.1%	8	8423
8/14/02	15	2,700	3,878	137		40	3,838	126	-1.0%	-8.2%	8	12845
8/14/02	16	2,696	3,912	150		30	3,882	141	-0.8%	-6.2%	8	11123
8/14/02	17	2,668	3,855	101		25	3,830	96	-0.6%	-5.2%	8	6129
Hourly Average		**2,445**	**3,806**	**92**	**#**	**30**	**3,776**	**87**	**-0.8%**	**-4.4%**	**5**	**5,562**
Total		**24,452**	**38,060**			**305**	**37,755**					**55,622**

Table 6-1D. April 2002 Value of Expected Un-served Energy, 5% Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 303	$ 455	$ 759	$ 1,517
0.10	$ 607	$ 910	$ 1,517	$ 3,034
0.15	$ 910	$ 1,366	$ 2,276	$ 4,552
0.20	$ 1,214	$ 1,821	$ 3,034	$ 6,069
0.25	$ 1,517	$ 2,276	$ 3,793	$ 7,586
0.50	$ 3,034	$ 4,552	$ 7,586	$ 15,172

EDRP Payments = $216,853

Table 6-2D. April 2002 Value of Expected Un-served Energy, 100% of Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 6,069	$ 9,103	$ 15,172	$ 30,345
0.10	$ 12,138	$ 18,207	$ 30,345	$ 60,690
0.15	$ 18,207	$ 27,310	$ 45,517	$ 91,034
0.20	$ 24,276	$ 36,414	$ 60,690	$ 121,379
0.25	$ 30,345	$ 45,517	$ 75,862	$ 151,724
0.50	$ 60,690	$ 91,034	$ 151,724	$ 303,448

EDRP Payments = $216,853

Table 6-3D. Summer 2002 Value of Expected Un-served Energy, 5% of Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 339	$ 509	$ 849	$ 1,697
0.10	$ 679	$ 1,018	$ 1,697	$ 3,394
0.15	$ 1,018	$ 1,528	$ 2,546	$ 5,092
0.20	$ 1,358	$ 2,037	$ 3,394	$ 6,789
0.25	$ 1,697	$ 2,546	$ 4,243	$ 8,486
0.50	$ 3,394	$ 5,092	$ 8,486	$ 16,972

EDRP Payments = $3,318,381

Table 6-4D. Summer 2002 Value of Expected Un-served Energy, 100% of Load at Risk

Reduction in LOLP	Outage Cost $1,000/MW	$1,500/MW	$2,500/MW	$5,000/MW
	($1,000's)			
0.05	$ 6,789	$ 10,183	$ 16,972	$ 33,945
0.10	$ 13,578	$ 20,367	$ 33,945	$ 67,889
0.15	$ 20,367	$ 30,550	$ 50,917	$ 101,834
0.20	$ 27,156	$ 40,733	$ 67,889	$ 135,778
0.25	$ 33,945	$ 50,917	$ 84,861	$ 169,723
0.50	$ 67,889	$ 101,834	$ 169,723	$ 339,446

EDRP Payments = $3,318,381

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
6/11	17	1,716	1,317	57.2	1	1,318	57.2	0.1%	0.1%	1.2	71	43
6/25	17	1,689	1,638	69.4	5	1,643	70.0	0.3%	0.9%	3.1	1,074	644
6/25	18	1,654	1,599	67.2	10	1,609	68.5	0.6%	1.9%	3.1	2,086	1,252
6/25	20	1,599	1,579	61.1	5	1,584	61.7	0.3%	1.0%	3.1	946	567
6/25	21	1,608	1,580	63.7	10	1,590	64.9	0.6%	2.0%	3.1	1,977	1,186
6/25	23	1,308	1,307	40.2	5	1,312	40.4	0.4%	0.5%	1.2	250	150
6/26	0	1,200	1,148	39.2	10	1,158	39.6	0.9%	1.1%	1.2	488	293
6/26	2	1,108	1,035	36.6	5	1,040	36.8	0.5%	0.6%	1.2	228	137
6/26	3	1,085	1,010	36.1	10	1,020	36.5	1.0%	1.2%	1.2	450	270
6/26	5	1,132	1,064	36.8	5	1,069	37.1	0.5%	0.6%	1.2	230	138
6/26	6	1,261	1,240	37.9	10	1,250	38.2	0.8%	1.0%	1.2	472	283
6/26	8	1,574	1,422	47.2	5	1,427	47.4	0.4%	0.4%	1.2	294	177
6/26	9	1,685	1,496	60.6	10	1,506	61.1	0.7%	0.8%	1.2	756	453
6/26	11	1,869	1,600	71.2	5	1,605	71.9	0.3%	1.0%	3.1	1,101	661
6/26	12	1,912	1,613	72.5	22	1,635	75.6	1.4%	4.3%	3.1	4,994	2,996
6/26	14	1,951	1,647	76.6	17	1,664	79.1	1.0%	3.2%	3.1	4,063	2,438
6/26	15	1,957	1,651	67.9	34	1,685	72.3	2.1%	6.5%	3.2	7,277	4,366
6/26	17	1,913	1,600	62.0	5	1,605	62.6	0.3%	1.0%	3.1	960	576
6/26	18	1,822	1,538	64.5	10	1,548	65.8	0.7%	2.0%	3.1	2,003	1,202
6/26	20	1,770	1,439	56.5	5	1,444	56.7	0.3%	0.4%	1.2	352	211
6/26	21	1,739	1,431	50.9	10	1,441	51.3	0.7%	0.9%	1.2	635	381
6/27	0	1,284	1,094	38.7	10	1,104	39.1	0.9%	1.1%	1.2	482	289
6/27	2	1,172	1,011	30.3	5	1,016	30.5	0.5%	0.6%	1.2	189	113
6/27	3	1,152	989	29.9	10	999	30.2	1.0%	1.3%	1.2	373	224
6/27	5	1,213	1,050	32.7	5	1,055	32.8	0.5%	0.6%	1.2	203	122
6/27	6	1,342	1,199	35.4	10	1,209	35.8	0.8%	1.0%	1.2	441	265
6/27	8	1,646	1,384	45.2	5	1,389	45.4	0.4%	0.5%	1.2	282	169
6/27	9	1,732	1,438	54.3	10	1,448	54.7	0.7%	0.9%	1.2	676	406
6/27	11	1,820	1,513	63.7	5	1,518	64.0	0.3%	0.4%	1.2	397	238
7/1	12	1,745	1,644	93.2	10	1,654	94.9	0.6%	1.9%	3.1	2,893	1,736
7/1	14	1,831	1,670	106.8	10	1,680	108.8	0.6%	1.9%	3.1	3,317	1,990

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
7/1	15	1,853	1,689	110.3	20	1,709	114.4	1.2%	3.7%	3.1	6,890	4,134
7/2	12	1,985	1,713	118.7	10	1,723	120.1	0.6%	1.2%	2.1	2,498	1,499
7/2	14	2,042	1,773	159.4	10	1,783	161.3	0.6%	1.2%	2.1	3,364	2,019
7/2	15	2,058	1,775	162.9	20	1,795	166.8	1.1%	2.4%	2.1	6,928	4,157
7/3	0	1,457	1,219	39.4	10	1,229	39.8	0.8%	1.0%	1.2	491	295
7/3	2	1,329	1,110	30.1	5	1,115	30.3	0.5%	0.6%	1.2	188	113
7/3	3	1,310	1,086	29.5	10	1,096	29.8	0.9%	1.1%	1.2	368	221
7/3	5	1,335	1,136	29.5	5	1,141	29.6	0.4%	0.5%	1.2	184	110
7/3	6	1,465	1,264	35.7	10	1,274	36.0	0.8%	1.0%	1.2	444	267
7/3	8	1,801	1,468	58.2	5	1,473	58.5	0.3%	0.4%	1.2	363	218
7/3	9	1,893	1,550	86.0	10	1,560	87.7	0.6%	2.0%	3.1	2,670	1,602
7/3	11	2,033	1,688	125.2	5	1,693	126.4	0.3%	0.9%	3.1	1,937	1,162
7/3	12	2,048	1,719	134.8	22	1,741	139.6	1.3%	3.6%	2.8	8,283	4,970
7/3	14	2,077	1,755	174.1	17	1,772	178.8	1.0%	2.7%	2.8	8,234	4,940
7/3	15	2,079	1,745	161.4	34	1,779	170.1	1.9%	5.4%	2.8	15,287	9,172
7/3	17	2,030	1,704	161.4	17	1,721	166.4	1.0%	3.1%	3.1	8,552	5,131
7/3	18	1,986	1,596	106.9	5	1,601	107.9	0.3%	1.0%	3.1	1,654	992
7/8	12	1,711	1,515	60.2	10	1,525	60.7	0.7%	0.8%	1.2	750	450
7/8	14	1,783	1,542	68.2	9	1,551	69.4	0.6%	1.8%	3.1	1,905	1,143
7/8	15	1,820	1,549	67.2	18	1,567	69.6	1.2%	3.6%	3.1	3,777	2,266
7/8	17	1,870	1,537	62.3	1	1,538	62.5	0.1%	0.2%	3.1	192	115
7/8	18	1,829	1,505	59.0	2	1,507	59.1	0.1%	0.2%	1.2	147	88
7/9	12	1,804	1,435	59.9	10	1,445	60.4	0.7%	0.9%	1.2	747	448
7/9	14	1,750	1,498	67.8	9	1,507	68.3	0.6%	0.7%	1.2	760	456
7/9	15	1,702	1,524	68.0	18	1,542	69.0	1.2%	1.5%	1.2	1,526	915
7/9	17	1,632	1,537	63.3	1	1,538	63.4	0.1%	0.2%	3.1	195	117
7/9	18	1,572	1,506	60.6	2	1,508	60.7	0.1%	0.2%	1.2	151	91
7/16	17	1,624	1,783	53.3	5	1,788	53.7	0.3%	0.8%	2.9	772	463
7/17	11	1,623	1,736	55.1	5	1,741	55.8	0.3%	1.1%	3.9	1,072	643
7/17	12	1,644	1,762	59.6	23	1,785	62.6	1.3%	5.0%	3.9	5,283	3,170

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in		Arc		
		Load in	Day-Ahead	Day-Ahead	DADRP	Day-Ahead	Day-Ahead	Due to DADRP		Price	Collateral	Bill
Date	Hr.	the RTM	Load (MW)	LBMP ($/MW)	Load (MW)	Load (MW)	LBMP ($/MW)	Load	LBMP	Flexibility*	Benefits ($)**	Savings ($)***
7/17	14	1,742	1,808	62.6	18	1,826	64.4	1.0%	2.9%	2.9	3,285	1,971
7/17	15	1,796	1,824	64.5	36	1,860	68.3	2.0%	5.9%	3.0	6,980	4,188
7/17	17	1,858	1,787	59.6	5	1,792	60.0	0.3%	0.8%	3.0	888	533
7/17	18	1,826	1,753	57.1	10	1,763	58.2	0.6%	2.0%	3.6	2,048	1,229
7/22	11	1,852	1,602	58.9	5	1,607	59.4	0.3%	1.0%	3.1	911	546
7/22	12	1,883	1,622	59.3	10	1,632	60.4	0.6%	1.9%	3.1	1,840	1,104
7/22	14	1,948	1,672	64.7	5	1,677	65.3	0.3%	0.9%	3.1	1,001	601
7/22	15	1,997	1,697	66.6	10	1,707	67.8	0.6%	1.8%	3.1	2,067	1,240
7/22	17	2,042	1,712	64.6	5	1,717	65.3	0.3%	1.1%	3.6	1,174	704
7/22	18	1,998	1,685	59.0	10	1,695	60.1	0.6%	1.8%	3.1	1,831	1,098
7/22	20	1,940	1,607	51.9	1	1,608	52.0	0.1%	0.2%	3.1	160	96
7/23	11	2,086	1,623	53.2	1	1,624	53.3	0.1%	0.2%	3.1	164	98
7/23	12	2,040	1,635	55.7	2	1,637	55.9	0.1%	0.4%	3.1	344	207
7/23	14	1,801	1,647	61.2	1	1,648	61.3	0.1%	0.2%	3.1	189	113
7/23	15	1,761	1,634	61.5	2	1,636	61.8	0.1%	0.4%	3.1	380	228
7/23	17	1,744	1,563	56.7	1	1,564	56.8	0.1%	0.2%	3.1	175	105
7/23	18	1,689	1,501	54.7	2	1,503	54.8	0.1%	0.2%	1.2	136	82
7/23	20	1,657	1,430	59.1	1	1,431	59.1	0.1%	0.1%	1.2	74	44
7/24	6	1,257	1,174	28.4	4	1,178	28.5	0.3%	0.4%	1.2	142	85
7/24	8	1,458	1,311	34.7	2	1,313	34.8	0.2%	0.2%	1.2	87	52
7/24	9	1,516	1,366	38.3	4	1,370	38.4	0.3%	0.4%	1.2	191	114
7/24	11	1,561	1,418	44.6	2	1,420	44.6	0.1%	0.2%	1.2	111	67
7/24	12	1,538	1,428	47.0	4	1,432	47.2	0.3%	0.3%	1.2	234	141
7/24	14	1,556	1,439	51.8	2	1,441	51.9	0.1%	0.2%	1.2	129	77
7/24	15	1,557	1,439	51.6	4	1,443	51.8	0.3%	0.3%	1.2	257	154
7/24	17	1,550	1,405	44.4	2	1,407	44.5	0.1%	0.2%	1.2	111	66
7/24	18	1,509	1,362	40.0	4	1,366	40.1	0.3%	0.4%	1.2	199	120
7/24	20	1,493	1,324	42.8	2	1,326	42.9	0.2%	0.2%	1.2	107	64
7/24	21	1,493	1,315	40.9	4	1,319	41.0	0.3%	0.4%	1.2	204	122
7/24	23	1,221	1,138	34.8	2	1,140	34.8	0.2%	0.2%	1.2	87	52
7/25	0	1,126	1,005	34.4	4	1,009	34.6	0.4%	0.5%	1.2	171	103

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Due to DADRP Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
7/25	2	1,047	899	28.1	2	901	28.2	0.2%	0.3%	1.2	70	42
7/25	6	1,196	1,067	25.4	4	1,071	25.5	0.4%	0.5%	1.2	127	76
7/25	8	1,447	1,277	30.9	2	1,279	31.0	0.2%	0.2%	1.2	77	46
7/25	9	1,507	1,351	41.0	4	1,355	41.1	0.3%	0.4%	1.2	204	122
7/25	11	1,579	1,408	40.8	2	1,410	40.9	0.1%	0.2%	1.2	102	61
7/25	12	1,558	1,416	41.7	4	1,420	41.8	0.3%	0.4%	1.2	208	125
7/25	14	1,582	1,427	42.0	2	1,429	42.1	0.1%	0.2%	1.2	105	63
7/25	15	1,580	1,424	43.0	4	1,428	43.2	0.3%	0.3%	1.2	215	129
7/25	17	1,587	1,384	40.4	2	1,386	40.5	0.1%	0.2%	1.2	101	60
7/25	18	1,543	1,340	39.6	4	1,344	39.7	0.3%	0.4%	1.2	197	118
7/25	20	1,518	1,298	38.4	2	1,300	38.5	0.2%	0.2%	1.2	96	57
7/25	21	1,500	1,310	40.6	4	1,314	40.8	0.3%	0.4%	1.2	203	122
7/25	23	1,238	1,149	36.8	2	1,151	36.9	0.2%	0.2%	1.2	92	55
7/29	9	1,838	1,597	62.1	1	1,598	62.2	0.1%	0.2%	3.1	192	115
7/29	11	1,944	1,734	78.6	1	1,735	78.8	0.1%	0.2%	3.9	310	186
7/29	17	2,082	1,844	89.9	1	1,845	90.1	0.1%	0.2%	3.3	300	180
7/29	18	2,035	1,803	79.6	2	1,805	79.9	0.1%	0.4%	3.3	533	320
7/30	9	1,885	1,710	68.1	1	1,711	68.3	0.1%	0.2%	3.8	257	154
7/30	11	2,010	1,812	86.0	1	1,813	86.2	0.1%	0.2%	3.7	318	191
7/30	17	1,963	1,798	105.8	1	1,799	106.0	0.1%	0.2%	3.8	399	239
7/30	18	1,918	1,745	88.9	2	1,747	89.3	0.1%	0.4%	3.8	672	403
7/31	9	1,842	1,713	83.5	10	1,723	85.7	0.6%	2.7%	4.7	3,902	2,341
7/31	11	1,923	1,838	107.0	5	1,843	108.0	0.3%	1.0%	3.6	1,941	1,165
7/31	17	2,041	1,812	126.2	5	1,817	127.4	0.3%	1.0%	3.7	2,318	1,391
7/31	18	2,005	1,745	105.2	10	1,755	107.4	0.6%	2.2%	3.8	3,981	2,388
7/31	20	1,941	1,677	85.7	5	1,682	86.5	0.3%	0.9%	3.1	1,326	796
8/2	11	1,926	1,795	102.5	1	1,796	102.9	0.1%	0.4%	7.9	804	483
8/2	12	1,891	1,797	120.8	2	1,799	121.9	0.1%	0.9%	7.8	1,882	1,129
8/2	14	1,795	1,797	156.0	1	1,798	156.7	0.1%	0.4%	7.3	1,134	680
8/2	15	1,750	1,780	145.3	2	1,782	146.5	0.1%	0.8%	7.3	2,118	1,271
8/2	17	1,653	1,726	106.8	1	1,727	107.3	0.1%	0.5%	7.8	833	500

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/2	18	1,601	1,666	93.1	2	1,668	93.4	0.1%	0.4%	3.1	575	345
8/12	9	1,738	1,633	56.5	2	1,635	56.7	0.1%	0.4%	3.1	349	209
8/12	11	1,915	1,759	76.2	1	1,760	76.5	0.1%	0.4%	6.7	509	305
8/12	12	1,949	1,794	79.1	4	1,798	80.2	0.2%	1.4%	6.1	1,925	1,155
8/12	14	2,002	1,833	105.9	2	1,835	106.6	0.1%	0.7%	6.2	1,319	791
8/12	15	2,016	1,852	108.9	4	1,856	110.3	0.2%	1.3%	6.2	2,718	1,631
8/12	17	2,029	1,889	98.6	2	1,891	99.2	0.1%	0.7%	6.3	1,234	740
8/12	18	1,997	1,838	77.4	4	1,842	78.5	0.2%	1.5%	6.9	2,127	1,276
8/12	20	1,932	1,766	68.2	1	1,767	68.5	0.1%	0.4%	6.9	472	283
8/12	21	1,889	1,732	60.3	2	1,734	60.9	0.1%	0.9%	7.5	911	546
8/13	9	1,798	1,689	45.3	2	1,691	45.5	0.1%	0.4%	3.1	280	168
8/13	11	1,957	1,813	72.9	1	1,814	73.1	0.1%	0.3%	5.9	432	259
8/13	12	2,007	1,831	76.4	4	1,835	77.3	0.2%	1.2%	5.4	1,662	997
8/13	14	2,064	1,858	104.6	2	1,860	105.2	0.1%	0.6%	5.6	1,170	702
8/13	15	2,083	1,864	109.4	4	1,868	110.8	0.2%	1.2%	5.6	2,454	1,473
8/13	17	2,093	1,850	88.9	2	1,852	89.4	0.1%	0.6%	5.5	978	587
8/13	18	2,041	1,796	72.4	4	1,800	73.4	0.2%	1.4%	6.2	1,786	1,072
8/13	20	1,992	1,718	60.6	1	1,719	60.8	0.1%	0.4%	6.0	365	219
8/14	9	1,873	1,633	50.3	2	1,635	50.5	0.1%	0.4%	3.1	311	187
8/14	18	1,887	1,793	95.5	4	1,797	97.1	0.2%	1.6%	7.3	2,793	1,676
8/14	20	1,883	1,733	73.4	1	1,734	73.7	0.1%	0.4%	7.3	539	323
8/14	21	1,853	1,702	68.6	2	1,704	68.8	0.1%	0.4%	3.1	424	254
8/15	11	2,033	1,771	83.6	5	1,776	85.4	0.3%	2.2%	7.7	3,212	1,927
8/15	17	1,962	1,728	122.8	5	1,733	125.3	0.3%	2.1%	7.1	4,364	2,619
8/15	18	1,915	1,668	89.8	10	1,678	91.5	0.6%	1.9%	3.1	2,787	1,672
8/16	12	2,114	1,833	104.9	8	1,841	108.1	0.4%	3.1%	7.1	5,959	3,575
8/16	14	2,069	1,862	185.3	8	1,870	191.0	0.4%	3.1%	7.2	10,732	6,439
8/16	15	1,904	1,836	213.5	16	1,852	227.2	0.9%	6.4%	7.3	25,099	15,059
8/19	12	1,797	1,712	49.5	8	1,720	50.5	0.5%	2.1%	4.5	1,789	1,073
8/19	14	1,836	1,741	108.0	8	1,749	110.3	0.5%	2.1%	4.6	3,939	2,363
8/19	15	1,855	1,759	76.9	16	1,775	80.1	0.9%	4.2%	4.6	5,637	3,382

Table 6-1E. Daily Effect of DADRP Scheduled Bids in the Capital Zone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/20	11	1,626	1,470	58.6	7	1,477	58.9	0.5%	0.6%	1.2	511	307
8/23	12	1,559	1,355	42.7	10	1,365	43.1	0.7%	0.9%	1.2	532	319
8/23	14	1,555	1,384	48.5	10	1,394	48.9	0.7%	0.9%	1.2	604	362
8/23	15	1,565	1,397	48.1	20	1,417	49.0	1.4%	1.8%	1.2	1,201	721
Hourly Avg.		1,733	1,553	70	7	1,559	71	0.4%	1.1%	3.0	1,696	1,018
Total		273,842	245,322		1,046	246,368					267,963	160,778

*As with most mathematical relations of this kind, the supply price flexibilities in the tables above are only vaild for small changes in load.
Here the supply models are calibrated to the observed prices, and in mathematical terms, the load response was large. The average "arc" flexibilities only approximate the averages from the tables.
**The collateral benefits are equal to the difference in actual and simulated LBMP multiplied by load served.
*** The bill savings are estimated to be 0.6 of the total collateral benefits. This assumes that an average of 40% of load is purchased through bilaterals. Thus, this net amount is the savings to customers buying load in the DAM.

Table 6-2E. Daily Effect of DADRP Scheduled Bids in the Western Superzone, Summer, 2002

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
7/1	11	8,502	7,884	57.3	10	7,894	57.4	0.1%	0.1%	1.2	662	397
7/1	12	8,615	7,969	60.0	20	7,989	60.2	0.3%	0.3%	1.4	1,648	989
7/1	14	8,851	8,069	63.6	10	8,079	63.7	0.1%	0.2%	1.6	1,029	618
7/1	15	8,807	7,986	55.1	20	8,006	55.4	0.3%	0.4%	1.7	1,905	1,143
7/1	17	8,707	7,606	51.3	10	7,616	51.4	0.1%	0.2%	1.8	903	542
7/4	12	7,802	6,027	45.1	20	6,047	45.4	0.3%	0.8%	2.3	2,088	1,253
7/4	14	7,687	6,020	45.1	10	6,030	45.3	0.2%	0.4%	2.3	1,044	626
7/4	15	7,627	6,027	45.0	20	6,047	45.3	0.3%	0.8%	2.3	2,084	1,250
7/4	17	7,436	6,068	37.9	10	6,078	38.1	0.2%	0.4%	2.3	877	526
7/4	18	7,259	5,991	37.9	20	6,011	38.2	0.3%	0.8%	2.3	1,753	1,052
7/5	12	6,541	6,151	46.6	14	6,165	46.9	0.2%	0.5%	2.3	1,511	906
7/5	14	6,499	6,132	47.1	7	6,139	47.3	0.1%	0.3%	2.3	763	458
7/5	15	6,474	6,052	48.0	14	6,066	48.2	0.2%	0.5%	2.3	1,555	933
7/5	17	6,223	5,893	46.9	7	5,900	47.0	0.1%	0.3%	2.3	758	455
7/5	18	6,114	5,746	45.2	14	5,760	45.5	0.2%	0.6%	2.3	1,466	879
8/12	9	7,933	7,618	53.6	6	7,624	53.8	0.1%	0.4%	5.2	1,680	1,008
8/12	11	8,671	8,213	73.2	3	8,216	73.4	0.0%	0.2%	5.7	1,245	747
8/12	12	8,861	8,345	75.8	6	8,351	76.1	0.1%	0.4%	5.4	2,472	1,483
8/12	14	9,138	8,564	101.2	3	8,567	101.4	0.0%	0.2%	5.9	1,793	1,076
8/12	15	9,150	8,543	103.8	7	8,550	104.3	0.1%	0.5%	6.0	4,364	2,618
8/12	17	8,969	8,414	93.6	4	8,418	93.9	0.0%	0.3%	6.1	2,287	1,372
8/12	18	8,736	8,203	73.6	8	8,211	74.1	0.1%	0.6%	6.3	3,717	2,230
8/12	20	8,579	7,915	65.1	4	7,919	65.3	0.1%	0.3%	6.0	1,553	932
8/12	21	8,373	7,804	57.5	8	7,812	57.8	0.1%	0.6%	6.2	2,830	1,698
8/13	11	8,907	7,884	67.1	3	7,887	67.2	0.0%	0.2%	5.4	1,078	647
8/13	12	9,146	7,964	70.1	6	7,970	70.4	0.1%	0.4%	5.2	2,176	1,306
8/13	14	9,382	8,118	91.0	3	8,121	91.2	0.0%	0.2%	5.6	1,524	914
8/13	15	9,347	8,094	95.6	7	8,101	96.0	0.1%	0.5%	5.6	3,773	2,264
8/13	17	9,167	7,861	80.8	4	7,865	81.1	0.1%	0.3%	5.5	1,780	1,068
8/13	18	8,954	7,642	66.3	8	7,650	66.7	0.1%	0.6%	5.8	3,061	1,837
8/13	20	8,747	7,533	56.4	4	7,537	56.6	0.1%	0.3%	5.2	1,178	707

Table 6-2E. Daily Effect of DADRP Scheduled Bids in the Western Superzone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/14	11	9,197	8,264	73.9	3	8,267	74.1	0.0%	0.2%	6.3	1,386	831
8/14	12	9,332	8,397	85.6	6	8,403	85.9	0.1%	0.4%	5.9	3,051	1,831
8/14	14	9,354	8,606	129.9	3	8,609	130.2	0.0%	0.2%	6.4	2,504	1,502
8/14	15	9,092	8,590	138.5	7	8,597	139.2	0.1%	0.5%	6.5	6,291	3,775
8/14	17	9,000	8,358	112.4	4	8,362	112.7	0.0%	0.3%	6.4	2,878	1,727
8/14	18	8,880	8,137	88.2	8	8,145	88.8	0.1%	0.7%	6.7	4,704	2,822
8/14	20	8,825	7,802	68.3	4	7,806	68.6	0.1%	0.3%	6.3	1,727	1,036
8/14	21	8,675	7,809	64.2	8	7,817	64.6	0.1%	0.7%	6.6	3,371	2,023
8/15	11	8,820	8,166	76.8	3	8,169	77.0	0.0%	0.2%	6.6	1,523	914
8/15	12	8,906	8,233	84.1	6	8,239	84.5	0.1%	0.5%	6.3	3,205	1,923
8/15	14	9,003	8,335	139.7	3	8,338	140.0	0.0%	0.2%	6.7	2,819	1,691
8/15	15	8,964	8,296	139.7	7	8,303	140.5	0.1%	0.6%	6.7	6,574	3,944
8/15	17	8,799	8,057	112.3	4	8,061	112.6	0.0%	0.3%	6.3	2,827	1,696
8/15	18	8,525	7,881	82.5	8	7,889	83.1	0.1%	0.7%	6.5	4,298	2,579
8/15	20	8,399	7,632	65.2	4	7,636	65.4	0.1%	0.3%	6.1	1,591	954
8/16	9	8,413	7,557	55.9	6	7,563	56.2	0.1%	0.5%	6.5	2,179	1,307
8/16	11	8,998	8,088	79.5	3	8,091	79.7	0.0%	0.2%	6.5	1,541	925
8/16	12	9,108	8,176	83.3	6	8,182	83.7	0.1%	0.5%	6.3	3,131	1,879
8/16	14	9,246	8,237	131.4	3	8,240	131.8	0.0%	0.2%	6.8	2,678	1,607
8/16	15	9,096	8,096	125.2	6	8,102	125.8	0.1%	0.5%	6.8	5,079	3,048
8/16	17	8,776	7,845	92.8	3	7,848	93.0	0.0%	0.2%	6.4	1,794	1,077
8/16	18	8,515	7,597	59.0	6	7,603	59.3	0.1%	0.5%	6.4	2,281	1,369

Table 6-2E. Daily Effect of DADRP Scheduled Bids in the Western Superzone, Summer, 2002 (cont.)

			With DADRP			Simulated		% Change in Due to DADRP		Arc		
Date	Hr.	Load in the RTM	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Day-Ahead Load (MW)	Day-Ahead LBMP ($/MW)	Load	LBMP	Price Flexibility*	Collateral Benefits ($)**	Bill Savings ($)***
8/16	20	8,382	7,196	47.4	3	7,199	47.5	0.0%	0.1%	2.5	353	212
8/17	11	7,999	6,723	41.8	2	6,725	41.8	0.0%	0.1%	2.3	193	116
8/17	12	8,057	6,814	51.8	6	6,820	51.9	0.1%	0.2%	2.3	719	431
8/17	14	8,025	6,827	59.5	3	6,830	59.5	0.0%	0.1%	2.3	412	247
8/17	15	7,944	6,872	60.6	5	6,877	60.7	0.1%	0.2%	2.3	701	420
8/17	17	7,848	6,920	53.0	2	6,922	53.1	0.0%	0.1%	2.3	245	147
Hourly Avg.		8,464	7,591	74	7	7,598	74	0%	0%	5	2,146	1,288
Total		499,382	447,847		422	448,269					126,611	75,967

*As with most mathematical relations of this kind, the supply price flexibilities in the tables above are only vaild for small changes in load. Here the supply models are calibrated to the observed prices, and in mathematical terms, the load response was large. The average "arc" flexibilities only approximate the averages from the tables.

**The collateral benefits are equal to the difference in actual and simulated LBMP multiplied by load served.

*** The bill savings are estimated to be 0.6 of the total collateral benefits. This assumes that an average of 40% of load is purchased through bilaterals. Thus, this net amount is the savings to customers buying load in the DAM.

Chapter 7 – PRL Business Model

Introduction

NYSERDA desires to develop a better understanding of the needs of business entities that are currently providing, or could provide, price-responsive load (PRL) services to end-use customers. A more in-depth characterization of how PRL services contribute to achieving various entities' core business goals can help NYSERDA design and administer Program Opportunity Notice (PON) programs that increase customer participation in PRL programs, and create sustainable business models for service providers. Last year, the PRL evaluation included a process survey that focused on how satisfied NYSERDA PON recipients were with the PONs in which they participated. This year, to broaden its perception on how it can promote demand response, NYSERDA expanded the scope of the analyses to a characterization of demand response as a business opportunity.

In addition to focus groups with PON recipients to solicit recommendations for improving existing programs, NYSERDA commissioned two additional inquiries directed at the content of future program design. The first involved conducting a survey with a variety of firms that either are, or might become, involved in promoting demand response in New York. A survey instrument was designed, tested, and administered to firms from a range of business interests that are or could be complemented by promoting demand response program participation, including regulated and competitive LSEs and technology vendors. The results of the survey shed light on the barriers to entry and identify leverage opportunities that NYSERDA must address in designing its PONs in order to expand the number of firms offering PRL products and services.

The second inquiry involved developing a financial representation of how demand response programs contribute to the bottom line of a curtailment service provider (CSP). A pro forma income statement was developed and used to explore the margin contribution that might be expected from recruiting customers to EDRP or ICAP service. To evaluate DADRP, a financial model was constructed to model DADRP as a call option. A more complex financial model is required to capture the inherent risk in bidding into the NYISO's market, which involves benefits and costs that are highly volatile.

NYSERDA PON Focus Groups

In 2001, NYISO and NYSERDA included a process survey for PRL program providers as part of the demand response program evaluation. In 2002, NYSERDA's interest focused on contractors who use NYSERDA funding to attract customers to participate in NYISO's price-responsive load programs. NYSERDA has designed two Project Opportunity Notices (PONs) primarily to facilitate participation in the NYISO programs: PON 609-01 (Enabling Technology) and PON 620-01 (Peak Load Reduction).

PON 609-01 was aimed specifically at demonstration projects that would enable customers to participate in the NYISO's PRL programs. The second initiative, PON 620-01, fosters the same ethic, but provided funding for a wider variety of investments that would help customers understand the time pattern of how they use electricity, and underwrite some of the cost of technologies and equipment (such as interval meters), that in the long run would enable them to exercise more control over that profile to reduce demand charges or to provide NYISO with additional system reserves.

PON 609-01: Enabling Technology for Price Sensitive Load Management

In support of NYISO's price responsive load programs, NYSERDA issued PON 609-01 to fund projects that developed and demonstrated technologies that facilitate load reduction in response to emergency and/or market-based price signals from NYISO. Emphasis was placed on innovative technology and organizational solutions, including communications, networking, advanced metering, and controls. Proposals sought project teams consisting of a NYISO market participant, a technology solution provider, and end-use customers that subscribed to one of the NYISO programs.

PON 609-01 was issued on November 20, 2001 with $1.0 million available and sought projects with co-funding of at least 50%. Responses were due to NYSERDA on January 9, 2002. Seven proposals were selected for awards for projects expected to provide participants for the summer 2002 PRL programs.

PON 620-01: Peak-Load Reduction Program

The Peak-Load Reduction Program offered funding for projects that result in reduced peak electric demand through short-duration load curtailment measures, permanent demand

reduction efforts, or through critically dispatched emergency generators. In addition, NYSERDA offered funding under this PON for installation of interval meters to encourage participation in NYISO's price responsive load programs. Public utilities, private-sector contractors and end-use customers participated in the programs. Participation in NYISO's EDRP program was strongly encouraged, but not mandatory to receive funding.

PON 620-01 was issued on December 24, 2001 with $10.5 million targeted for summer peak load reduction measures and grid connected photovoltaic (PV) systems. Applications were accepted on a first-come, first-served basis through October 1, 2002. NYSERDA awarded $2,387,300 to 223 projects in the Short Duration Load Curtailment, Dispatchable Emergency Generation or Interval Meter categories that were completed by early August, 2002. This funding produced 125 EDRP participants (including two that also received funding under PON 609, for projects that were awarded $6,000 of the PON 620 total). Seven EDRP participants who applied for funds under PON 577-00 completed projects for the summer 2002 season and were awarded $393,280.00 for these Peak Load Reduction projects. Additional projects completed by December 19, 2002 brought the PON 620-01 total to 481 projects awarded for a total of $4,906,230.42.

Details of performance metrics for NYSERDA's PON recipients enrolled in NYISO programs can be found in Appendix 7A.

Focus Group Meeting Objectives

NYSERDA wanted to learn from its PON contractors what barriers they encountered in enrolling customers in NYISO programs, particularly in downstate, and to solicit suggestions for improving the PON application process and interactions with NYSERDA, and ideas for improving NYSERDA and NYISO programs. Contractors from PONs 609 and 620 who had participants in NYISO's demand response programs were invited to participate in one of two focus group meetings conducted by Neenan Associates and held in September. Representatives from four PON contractors attended the Syracuse, NY meeting, six attended in New York City, and two who were unable to attend but provided their comments to Neenan Associates in writing.

Challenges in Recruiting Customers

This year, the NYISO programs experienced substantial growth in participation in two of the three demand response programs, EDRP and ICAP/SCR. DADRP registrations changed only

slightly with six participants leaving the program and four new participant registering. With the exception of the LIPA *Edge* Program, the majority of new participants in EDRP were primarily upstate, especially in western and central New York. Enrollments in New York City doubled from 2001, but still lagged far behind enrollments upstate. The focus group participants were asked what aspects of the NYISO programs presented challenges in subscribing participants and what issues they encountered when signing up participants for NYSERDA funding.

The following challenges were cited in recruiting customers for NYISO demand response programs:

- Some aspects of program too complex;
- Uncertainty about program features and longevity of programs;
- DEC permit changes regarding participation in EDRP did affect some participants in NYC;
- Delay of payments - experience with or word of mouth regarding 2001's delays in settlement payments;
- For DADRP, the 1 MW bid minimum was cited as a major reason for not participating; most customers in NYC could not accommodate a minimum load reduction of this size; and
- Landlord/tenant issues are a significant barrier to subscribing participants in New York City.

Contractors indicated that the multiple steps required to obtain project approval for a PON application was a major factor in reduced applications in New York City; customers would lose interest after a number of steps and cancel the project.

Suggestions to NYSERDA

The focus group participants offered several suggestions for NYSERDA on how to improve PON applications, public awareness of NYSERDA and the demand response programs, and create an environment in which more contractors would participate in NYSERDA programs. Most themes were common to both upstate and downstate focus group participants:

1. **Education is a necessity for end-users.**

NYSERDA has historically funded hardware to support energy efficiency. Demand response programs require education about how electricity is being used and strategies for behavioral changes to achieve new levels of energy efficiency. This can only be achieved through continuing education, both at the contractor and end-user level. Since much of the interaction occurs at the contractor to end-user level, PON contractors suggest that a greater portion of PON funding be allocated to contractor-to-end-user education activities, and support the development and execution of behavioral strategies for participation in demand response programs.

2. **Milestone billing for PON projects.**

   Most of the PON contractors who participated in the focus groups are small to medium sized firms. As such, it is difficult for these firms to independently fund large installations of PON projects, and receive no reimbursement until they have been completed. All focus group participants agreed that they are strongly in favor of some type of milestone billing for PON projects.

3. **PON cycles don't match customers' budget cycles.**

   Typically, PONs for demand response programs are issued at the end of the calendar year or at the beginning of the calendar year with the intent of having projects installed for the summer. This does not coincide favorably with the budget planning process of most businesses, even those on a calendar year budget where planning is usually done in late summer or early fall. Contractors feel that this is a significant barrier to getting customers to apply for NYSERDA funding – it's either too early or too late to match the customer's planning cycle. *See also #5 – PON contracting process takes too long.*

4. **Improve communication and support for PON application process.**

   Focus group participants emphasized the need for better communication and support for the PON application process. Specifically:

   - For open-enrollment PONs, an up-to-date funding availability status is essential to contractors, perhaps on the NYSERDA web site. Continuing to enroll customers in a PON that is exhausted is embarrassing to the contractor, and reduces customer's confidence in both the contractor and NYSERDA.

- During the PON application period, staffing should correspond to the anticipated response to the PON – contractors suggested that staffing should be determined based on PON funding amount.
- PONs should be released on time – some PONs have been promised for several months before release. This makes it difficult to keep a customer's interest in NYSERDA funding, and causes delays in project implementation.
- Implement a method to get answers for projects that cut across multiple PONs – Contractors indicated that when a project could receive funding from multiple PONs for various aspects of the project, it was difficult to obtain clear answers regarding how the applications might affect one another.

5. **PON contracting process takes too long.**

   Most contractors mentioned of having been notified of awards to PON applications with adequate time to complete the project, but the contracting process to get the P.O. usually dragged on, causing the project to be severely delayed or canceled. Customers would then become disappointed and not interested in future projects with the contractor or NYSERDA. For PONs with payments based on installation by a certain date, there can be a significant difference in the amount of funding received. *See #6 – Timeframes for PON applications and project completion need more flexibility and simplicity.*

6. **Timeframes for PON application and project completion need more flexibility and simplicity.** Contractors felt that, particularly when PON releases are delayed or when the response period includes holiday periods, more time should be given for response to a PON. In addition, because of the delays experienced between award notification and contract signing, PONs should have a more flexible completion date that is tied to the contract date instead of a fixed date specified by NYSERDA at the time the PON is first issued. It was also suggested that PONs specify different completion dates and incentives for summer peak vs. winter.

7. **PONs should track the NYISO programs they are targeting.**

   PONs issued specifically to support participation in NYISO demand response programs should have extended application and fulfillment periods that correspond to the duration of the NYISO demand response programs they are targeting for participation. This would allow contractors to attract new participants on a schedule that is favorable for the

customer with minimal changes to PON requirements during the limited time windows for current PONs. It was suggested that updates to payment amounts would be acceptable, but criteria for eligibility for funding should remain constant to reduce confusing customers and contractors as well.

8. **Become involved in seminars and industry groups.**

   It was suggested that NYSERDA become more involved with industry groups and participate in industry seminars. While most contractors acknowledged that they have attended NYSERDA-sponsored seminars, they indicated that repeat participation in industry trade groups and seminars would increase end-user awareness of NYSERDA funding opportunities. This increased awareness would create a more vibrant follow-on market for NYSERDA contractors.

Characterizing Market Maker Preferences

As part of the 2002 PRL program evaluation, NYSERDA supported an initiative that involves extending the inquiry to a wide variety of firms that are, or potentially might become, involved with the provision of PRL services to retail customers. Such firms are referred to as market makers and this section describes research conducted to characterize how these firms view demand response as a business opportunity.

To solicit market makers' views on how PONs can best serve their needs, an interview instrument was developed and administered to 15 different firms. The firms included representatives from six enterprise categories that are characterized as follows:

1. POLR/ default service providers comprised of the existing six IOUs in the state, NYPA, LIPA, and cooperatives. We expect that their primary interest is to reduce their supply costs, although some may use PRL services to better manage the local distribution system, or contribute to the maintenance of system reliability.

2. Competitive Retailers that offer commodity services to end-use customers. These include those that are currently active and potential new entrants. PRL might be used as a loss leader to attract customers to their commodity services, or integrated into their service portfolio to be able to offer a wider variety of choices in service plans.

3. Performance ESCO contractors that integrate PRL participation into more conventional DSM and energy services provision under some form of performance contractual arrangement.

4. Wholesale traders/brokers that deal in the physical commodity that could trade PRL rights and obligations and use them to cover short supply positions in day-ahead or real-time markets.

5. CSP boutiques whose sole objective is to profit from providing customers with access to NYISO PRL programs on terms that better accommodate individual capabilities and preferences for risks.

6. Enabling technology firms that manufacture and/or distribute technologies that aid customers in designing and executing curtailment strategies that facilitate participation in PRL programs.

The interview instrument was constructed to collect basic business activity information from each firm and to characterize their past and current activity in electricity markets, with an emphasis on experience with demand response programs. A copy of the survey instrument is provided in Appendix 7B.

Neenan Associates recruited firms to participate, and scheduled and conducted the interviews. The survey responses were characterized by categories that share common objectives with regard to how PRL can help them achieve their business goals, and then the results were used to characterize the perspectives of market makers, which have some common elements, but also display considerable diversity of opinion as to how NYSERDA funding can be effective in promoting demand response.

Surveys were completed by 16 firms, including three regulated LSEs, one competitive LSE, three information service providers, six controls companies and two ESCOs. Over half of these firms are already operating in the NY state market, and the rest say they are considering entry. These firms were asked what investment return criteria they would apply in considering investments in demand response. The rate of return thresholds ranged from as low as 10% to as high as 75%, and averaged 33%. The average payback period reported was 2.7 years. Clearly, these firms have high hurdle rates for investment in demand response as a business. This finding is all the more striking, since all but one indicated that they view demand response as a means of complementing their main, much larger, business aspirations. They apparently are not so

optimistic about the potential of demand response complementing their business that they are willing to use it as loss leader or to subsidize it.

Survey respondents offered their views as to the major barriers to demand response as a vital aspect of their business. Market design uncertainty (i.e. the lack of a clear, concise, and permanent role for demand response in the standard market design) was identified as the number one barrier by four respondents and three named it as the number two barrier. Several respondents opined that generation or regulated LSE interests prevailed in making the rules, and they would be biased against demand response. Another considers it a fad that would go away in a year or two.

Three respondents named customer uncertainty about program benefits as the number one barrier, and another three named it as the number two barrier. Uncertainty on the customer's part translates into resistance to overtures to participate, and results in higher customer acquisition costs. Remarks included the observation that only the very largest customers are aware of, and have any experience with curtailment programs to draw upon, that there is too little information about how NYISO prices are set to dispel customers' almost primal fear of market uncertainty, and that misconceptions on customers' part of legacy programs act as deterrents to participation. This theme was echoed by the four respondents that said that low ROIs for participation is the main barrier to their participation - they cannot justify the investment expense. One named CBL uncertainty as the source of low ROI, another attributes it to the speculative nature and low incidence of curtailment events. Only one respondent named the imposition of noncompliance penalties as a barrier to its participation, and that respondent rates it as the third greatest barrier it faces.

Twelve of the 15 respondents said that they favored the expenditure of public benefit funds to promote demand response program participation. The dissenters were two regulated LSEs and an ESCO, each expressing the belief that demand response should not be subsidized, but left to the competitive market to establish value. Of those that responded, about 40% felt that the ISO should be the entity to design and implement demand respond programs directly to customers, while about half felt

Table 7-1. Who Should Offer DRP Programs to Retail Customers?

Response	Freq	Respondent type
ISO directly	4	2 LSEs 2 ESCOs
ISO through CSPs	5	1 LSE, 4 CSPs
LSEs (not the ISO)	1	1 CSP

the ISO should design them, but use CSPs to implement the programs. One respondent expressed the belief that the ISO should leave the promulgation of such programs to the competitive retail market (see Table 7-1).

Eight respondents said that they had experience with legacy load management programs operated by a utility in a vertically integrated electricity market, three have experience with an ISO program other than in New York, and three different respondents have been involved in the NYISO's PRL programs. Those involved in legacy programs reported that the program has been either abandoned or closed to new subscriptions, due to changes in the market that have rendered the design no longer cost effective.

A key aspect of the survey was an exercise whereby survey respondents first ranked alternative PON areas of focus according to their value to the respondent's business interests, and then indicated how they would like to see PON funding allocated over these program focus areas. The focus areas respondents considered are as follows:

1. **General customer education**. Providing customers with workshops and seminars, and preparing and distributing brochures that describe the benefits of program participation.
2. **Customized customer education and consulting**. Conducting audits of customer premises to identify curtailment capabilities, and using the results to develop a curtailment strategy.
3. **Marketing and administrative support**. Providing funds explicitly to offset the costs of marketing programs to customers and administering their participation.
4. **Essential Technology funding**. Incentives for the purchase and installation of interval meters, and offsets for the costs of meter reading.
5. **Enabling Technology funding**. Incentives for investments in technology that enable the customers to retrieve prices, event information, and its own meter readings, and to use the data to develop and execute a curtailment strategy.
6. **Back office funding.** Funding to offset the cost of program administration and billing.
7. **Augment Program benefits**. Supplement to the NYISO market-based curtailment payment levels to enhance program participation.

Results of the ranking exercise are displayed in Fig. 7-1. Respondents scored the seven program features on a scale of one (little or no value) to six (very high value), based on how they would contribute to each's business interest regarding demand response. Funding for technology investment by customers received the highest ratings (based on the average score), with that for enabling technologies (information services and controls) slightly higher (4.9) than the score for essential technologies (meters), which received an average score of 4.6. Subsidies for program benefits received almost the same average score (4.6). All other features scored below the overall average score of 3.8 out of six.

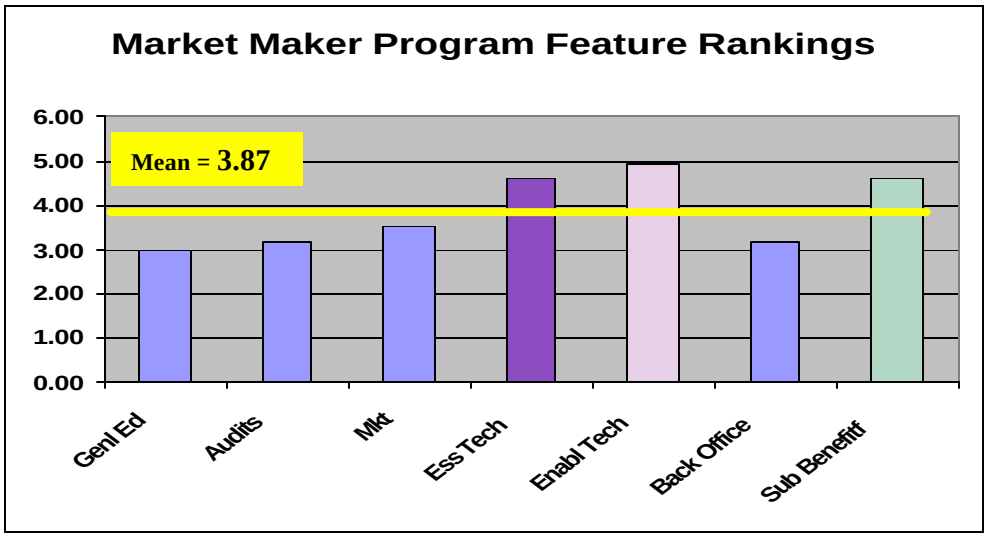


Fig. 7-1 Program Feature Rankings

Scores were the most dispersed for the general education, customized audits, and marketing services program categories, each of which received at least six scores of one or two (low preferences for these programs) but also received at least two scores of 6 (high preference). Subsidies also showed diversity of interest, with six scores of six, including one regulated LSE, but two scores of two or less (one competitive and one regulated LSE). LSEs are obviously not of one mind as to how PON funding to promote demand response can contribute to their business interests.

Responses for the second program feature rating exercise (allocating funding over the various categories) are displayed in Fig. 7-2. (Allocations were made on a relative basis, so scores represent the percent of PON funds to be allocated.)

The allocation of PON funds by respondents over the features offered mirror the preferences in that technology subsidies received the greatest emphasis (27% of funding allocated, on average, to enabling technology PONs and 20% to essential technologies). However, the funding priorities diverge from the ranking for the other factors. Customer-specific audits received the third highest allocation, on average. Subsidies for benefits, which were third in the relative rankings, received the third lowest allocation on average, about 9%.

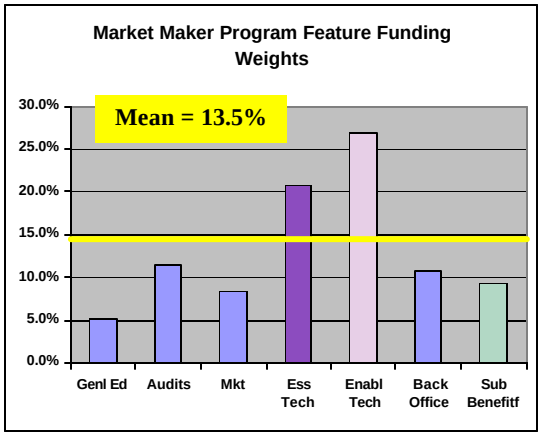
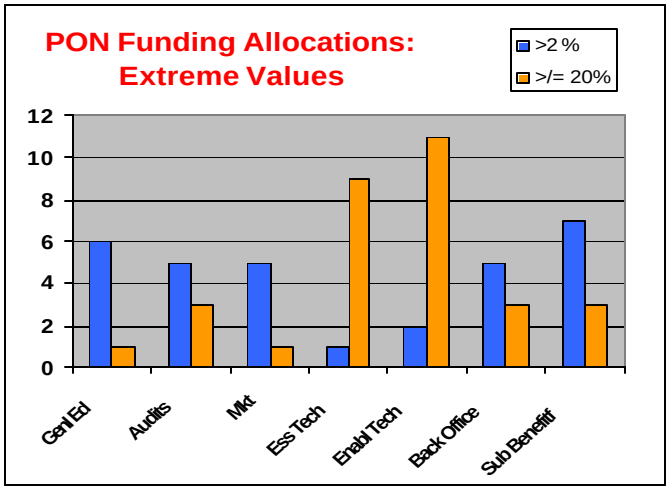


Fig. 7-2 Program Feature Funding Weights

Individual funding allocations varied widely for some features, but were quite uniform for others. The largest allocation was 60% for enabling technologies (offered by a technology supplier). Two 50% allocations were also made (one to each technology category), with both made by an unregulated retailer. There were many zero allocations, which make the distribution of allocations interesting.



The two technology categories received a high number of allocations above 20% (the mean allocation was about 14%), and only 1 or 2 zero allocations. (It was an ESCO that voted no allocation to either technology category.) The same distribution, but with the opposite results, characterized allocations for general education, (which received six zero funding allocations and only one value over 20%), and for marketing, which has approximately the same distribution of scores.

The other categories exhibit more highly polarized opinions. Allocations for PRL audits, back office costs, and subsidies for benefits had a much more even mix of high and low allocations. Respondents are clearly not of one mind regarding PON funding of these initiatives.

Business Case Studies

Two financial models were developed to explore how demand response programs could contribute to market makers' business interests. The first, described below, utilizes a financial pro forma income statement to characterize the costs and benefits that flow from recruiting participants to the EDRP and ICAP/SCR programs. The following section extends the analysis to DADRP using a more complex representation of market conditions and their uncertainties.

EDRP/ICAP SCR Pro forma Income Statement

Description of Income Statement Approach

The Income Statement Approach characterized the PRL business opportunity by simulating three years of financial performance for a hypothetical curtailment service provider (CSP) that recruits customers to participate in the EDRP and/or ICAP programs.[1] This performance was simulated under a variety of representative market conditions and PRL program rules to demonstrate the sensitivity of the performance to parameter levels. The combinations of conditions modeled are shown in Fig. 7-4.

Fig. 7-4 Perspectives on CSP Business Opportunity

	Spring 2002		Spring 2003
Upstate	EDRP&ICAP / PON		EDRP / PON
	EDRP&ICAP / No PON		EDRP / No PON
			ICAP / PON
			ICAP / No PON
Downstate	EDRP&ICAP / PON		EDRP / PON
	EDRP&ICAP / No PON		EDRP / No PON
			ICAP / PON
			ICAP / No PON

Notes: Spring 2002 perspective is more advantageous than Spring 2003. For Spring 2002:
a) It was assumed that event hours would continue at 2001 levels.
b) It was assumed that loads could remain enrolled in both EDRP and ICAP.
c) It was assumed that EDRP are received, in full, for all events.

These variations in input were organized into two main groups, called Perspectives. The Spring 2002 Perspective reflects the view of a prospective CSP entrepreneur, considering entering into business in advance of the 2002 season, and expecting that the experience of 2001 would continue for (at least) three years. Thus the pro forma modeling for the Spring 2002 cases

[1] ICAP in this discussion refers to ICAP Special Case Resources.

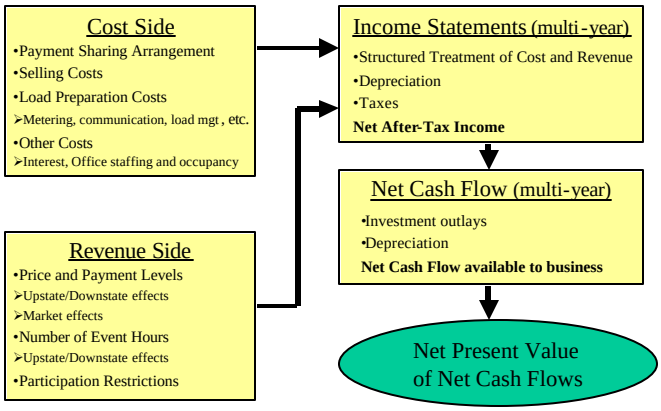
assumes 2001 values for program rules, actual event hours experienced, and curtailment prices. Within those "2001 repeats" assumptions, the modeling explores the effects of location (upstate vs. downstate) and the availability of NYSERDA cost sharing (PON vs. No PON) on performance.

The Spring 2003 perspective updates the previous year's perspective with the experience of the 2002 season, and incorporates recent revisions in the NYISO program rules. In the Spring 2003 perspective, it is 2002 conditions that are expected to continue for three years. Within these "2002 repeats" assumptions, a similar set of variations is explored. Since one of the important changes between 2002 and 2003 is that dual EDRP/ICAP registration of a given load is no longer permitted, the Spring 2003 perspective breaks out EDRP and ICAP, and explores the alternatives of registering customers entirely in EDRP versus entirely in ICAP.

Analysis Method

To calculate and describe the results of each combination of assumed conditions, two standard tools of financial analysis and project evaluation were used (see Fig. 7-5). A pro forma Income Statement was produced for each of the three years of operations. An income statement is the classic way to show the financial performance of a business over a specified time period. In addition to the obvious costs and revenues, an income statement reflects the need of a real-world business to pay less obvious costs, such as interest and office rent. It also provides for the proper accounting for depreciation and taxes. All of these components are summarized into the classic "bottom line" – which in our case is net cash flow available to the business.[2]

Fig. 7-5 Income Statement Modeling Approach



[2] For an established enterprise, net after-tax income is commonly used as the bottom line. Because our hypothetical CSP is created in the first year, we want to reflect the up-front investment necessary to start operations.

The second standard tool is Net Present Value (NPV) of the net cash flows available to the business. Using NPV allows further summarization of the financial performance results into a single figure of merit for each scenario.[3]

Assumptions

The CSP is assumed to be managing 50MW of enrolled capacity. The load consists of commercial (25%), industrial (15% with cogeneration, 25% without cogeneration), institutional (10% with cogeneration, 20% without cogeneration), and residential (5%). Key inputs that drive the income statement are revenue sharing arrangements with end users, event hours and payment levels, program design (e.g. can a load be in both EDRP and ICAP?), one-time and recurring costs of enrolling and preparing loads to perform, and the availability of NYSERDA cost sharing.

Revenue Assumptions:

- The CSP was assumed to retain 40% of its gross curtailment payments, with the other 60% being paid out to subscribers.
- EDRP summer event hours were based on actual values 2001 and 2002. (Note: the April 2002 events were not included, because they occurred before most loads were registered and ready.) In 2001 there were 17 events hours upstate and 23 event hours downstate. In 2002 there were 12 event hours statewide.
- Prices for ICAP were taken from the results of the May auction for the entire summer capability period. The payments per MW for downstate were $52,500 and $55,200 for 2001 and 2002 respectively. For upstate, the payments were $11,400 and $11,500 for 2001 and 2002, respectively.
- EDRP energy payment levels were assumed to be $500/MWh, which was the case in all event hours of 2002 and most event hours of 2001.[4]

[3] Another commonly used figure of merit is Return on Investment (ROI). Because ROI is undefined unless a series of cash flows has at least one change of sign, it does not work for such a broad range of input assumptions.

[4] EDRP provisions call for the payment of the higher of $500/MWH or the prevailing NYISO real-time LBMP for all hours of event that are four or more hours in duration.

- In accord with the recent change in NYISO program rules, EDRP will no longer be called automatically when there is an event. For the Spring 2003 perspective, it was assumed that loads in EDRP would be called only 2/3 of the time that an event was declared.
- Another recent change in program rules, that a given load may not be registered in both EDRP and ICAP, is modeled in the Spring 2003 perspective.
- Energy payments are a new feature of ICAP for 2003. These payments are separate from those paid to EDRP participants, and will be market determined. For modeling purposes, ICAP energy payments were estimated to be $250/MWh (or half of historic EDRP levels).[5]

Cost Assumptions: Costs were assumed to be invariant to changes in either location (upstate or downstate), or program (EDRP or ICAP). Thus the different financial performance results are being driven by differences in revenues. The assumed total costs for enrolling 50 MW of loads, and for preparing them to perform, were $138K and $564K, respectively. On a $/kW basis, these costs are $2.76 and $11.28. PON cost sharing was assumed to be 60% of load preparation costs. Compared to actual experience of PON participants, these costs are considered reasonable, or even optimistic. Fixed office and salary costs of ~$150K per year also seem conservative.[6]

Performance Assumptions: All registered loads were assumed to perform at 100% when called. This assumption has two favorable impacts on the pro forma results. First, ICAP performance penalties are avoided. Second, EDRP energy payment revenues are received at maximum value.

Taxation Assumptions: Income tax liability was allowed to assume negative values when pre-tax income was negative. These negative tax liabilities thus had a positive effect on net cash flows for the years in which they occurred. There is a two-part rationale for this treatment of taxes:

- It was assumed that the CSP line of business was part of a larger tax-paying entity.

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[5] Under the new rules, ICAP/SCR customers must submit strike prices with their applications, and those prices are used to construct a bid curve that is used to determine which resources are dispatched. Those that are dispatched receive the price they bid.

- It was assumed that the larger entity was profitable, and could take full advantage of any tax losses generated in CSP operations.

A related taxation assumption is the treatment of depreciation (which was only applied to out-of-pocket load preparation costs, after cost sharing). Depreciation is deducted from operating revenue to calculate taxable income, then added back in to after-tax income to calculate net cash flow. This treatment has the effect of sheltering depreciation from taxes, but recognizing that the charge does not actually reduce available cash.

Because the above assumptions are either well within observed experience, standard practice, or actually favor the modeled financial results for our hypothetical CSP, the modeling approach used is unlikely to understate the results for a real-world CSP.

Results and Conclusions from the Income Statement Approach

Figure 7-6 summarizes the results of pro forma modeling of the PRL business opportunity using the Income Statement Approach. For each box in the figure, the monetary amount is the model result (in thousands) for the net present value of cash flows available to a hypothetical CSP business from 3 years of operations. The boxes represent different assumptions about where the CSP is located, program rules and market conditions that will determine his revenues, the availability of NYSERDA cost sharing, and the PRL programs in which its customers and their curtailment loads are registered. The salient model results are:

Fig. 7-6 Pro Forma Modeling Results
(NPV in $Thousands)

	Spring 2002	Spring 2003
Upstate	EDRP&ICAP / PON $128	EDRP / PON ($263)
	EDRP&ICAP / No PON ($162)	EDRP / No PON ($552)
		ICAP / PON ($54)
		ICAP / No PON ($344)
Downstate	EDRP&ICAP / PON $1,632	EDRP / PON $280
	EDRP&ICAP / No PON $1,343	EDRP / No PON ($9)
		ICAP / PON $1,471
		ICAP / No PON $1,181

- It is difficult to make money upstate. Of all the upstate cases examined, only the combination of Spring 2002 assumptions and NYSERDA cost-sharing lead to a positive NPV. (This result will be discussed more fully below.)

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[6] It would seem, however, from the amount of observed CSP activity upstate that some real-world CSPs

- The change from a Spring 2002 to a Spring 2003 perspective decreases NPV for every case modeled, but especially for EDRP. The only non-negative NPV for EDRP alone under 2003 assumptions is downstate, assuming PON cost sharing for load preparation costs.
- Under Spring 2003 assumptions, stand-alone ICAP is much more profitable (or less money-losing) than EDRP. This is especially true downstate, where the ICAP auction prices are much higher.

Regarding the business prospects for a start-up CSP specializing in either EDRP or ICAP, two key conclusions can be drawn from these results:

Only under very favorable cost conditions does EDRP make economic sense as a stand-alone business opportunity.

If 2002 market conditions and 2003 program rules persist in the future, only some of the costs can be recovered from the revenue to be expected from EDRP. The only likely scenarios in which a profit-seeking, start-up CSP would be prudent to pursue EDRP loads is as part of a portfolio of products, in which at least one of the following occur:

- The EDRP line of business produces other benefits (such as cross-selling opportunities) that justify or offset its minimal or negative contribution to profits.
- The costs of enrolling and preparing loads are either very small, or can appropriately be charged to some other line of business (without destroying the profitability of that line of business).
- The CSP is already established and its customer acquisition costs are sunk.

Downstate EDRP was considered, and rejected, as a possible exception to this statement. Both the PON and No PON cases produced positive cash flows in the first year, but went negative in 2003, as the exclusion of EDRP loads from ICAP took effect.

Only downstate is ICAP a viable stand-alone business opportunity

Both modeled ICAP cases lose money upstate. Downstate, where auction prices are more than 5 times the upstate values, ICAP makes money with or without PON cost sharing.

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have been able to register and deliver loads at costs lower than these.

Inclusion of DADRP in the CSP Business Case

A natural extension of this analysis is to see if these stand-alone prospects could be substantially improved if a CSP were also to participate in DADRP. As shown in the next section, economic valuation of DADRP revenues requires the valuation of a strip of options. A rough, preliminary valuation of DADRP is done in that section, and the results are used here to simulate the effects on CSP financial performance of combining DADRP with ICAP. In addition to using preliminary results for DADRP option valuation, the analysis is subject to the following simplifying assumptions:

- Only the combination of DADRP with ICAP is evaluated.
- A simple comparison of the present values of expected costs and revenues is used, instead of the income statement approach.
- It is assumed that the same loads can participate in both DADRP and ICAP, and full value can be derived from each program (i.e. there is no modeling of interactions between payments received for DADRP and for ICAP).
- Load enrollment and preparation costs are modeled parametrically.
- Operations costs are assumed to be $500K/yr (compared to $150K, above). The increase is to reflect the complexity in monitoring and bidding required for DADRP participation.

Table 7-2 Revenue and Cost Values Used in Simplified DADRP/ICAP Model

	Natural Units	Present Value ($/MW)
Revenue Components		
DADRP Option Value		
100 Hours/Month	40% of Option Value of **100** Hrs/Month, Bid@ $100/MWh	**28,000**
200 Hours/Month	40% of Option Value of **200** Hrs/Month, Bid@ $100/MWh	**55,600**
PV of ICAP Payment Stream		
Upstate		
3 Years	40% of $13,500/yr for **3** yrs, discounted at 7%	**14,171**
5 Years	40% of $13,500/yr for **5** yrs, discounted at 7%	**22,141**
Downstate		
3 Years	40% of $58,200/yr for **3** yrs, discounted at 7%	**61,094**
5 Years	40% of $58,200/yr for **5** yrs, discounted at 7%	**95,453**
Cost Components		
Operating Costs	$500K/yr for 50 MW --> $10K/yr/MW for 5 yrs, discounted at 7%	**16,401**
Acquisition Costs		
Low	$**15**/kW (incurred in Year 0)	**15,000**
Medium	$**30**/kW (incurred in Year 0)	**30,000**
High	$**60**/kW (incurred in Year 0)	**60,000**

The various values used for revenue and costs are displayed in Table 7-2, both in "natural" units, and converted to present values. To avoid having to model every possible combination of input values, the cost and revenue "components" of Table 7-2 are combined into nine distinct scenarios (see Table 7-3), and the scenario set was simulated once for downstate ICAP prices, and once for upstate ICAP prices. Moving down the rows of Table 7-3, what changes are the amount of hours of DADRP bid per month (200 in the "High" and "Medium" revenue scenarios, 100 in "Low"), and the number of years of ICAP payments expected (5 in "High", 3 in "Medium" and "Low"). Moving across the columns, the only changes are to the $/kW values assumed for the cost of enrolling loads and preparing them to perform (15, 30, and 60 for "Low", "Medium", and "High", respectively).

Table 7-3 Scenario Cost & Revenue Components
DADRP and ICAP

Revenues		Costs: Low	Costs: Medium	Costs: High
High	DADRP Bids (Hrs/Month)	200	200	200
	ICAP Duration (Yrs)	5	5	5
	Load Acquisition Cost ($/kW)	15	30	60
Medium	DADRP Bids (Hrs/Month)	200	200	200
	ICAP Duration (Yrs)	3	3	3
	Load Acquisition Cost ($/kW)	15	30	60
Low	DADRP Bids (Hrs/Month)	100	100	100
	ICAP Duration (Yrs)	3	3	3
	Load Acquisition Cost ($/kW)	15	30	60

Financial performance results for these scenarios, expressed as the present value of revenues minus the present value of costs, are given in Table 7-4 for downstate, and Table 7-5 for upstate. Since ICAP Alone was profitable downstate, it is not surprising that it is profitable downstate in combination with DADRP. Note, however, that even here, the value is marginal under the Low Revenue/High Cost scenario. (100 hrs/month of DADRP bids, 3 years of ICAP payments, $60/kW load acquisition cost). Note also that $60/kW is not "high" relative to the acquisition costs experienced by NYSERDA PON contractors.

Table 7-4 Simplified NPV: Downstate
1 MW CSP w DADRP and ICAP Loads
Using Downstate ICAP Auction Values
($Thousands/MW)

Revenues	Costs: Low	Costs: Medium	Costs: High
High	120	105	75
Medium	85	70	40
Low	58	43	13

Table 7-5 Simplified NPV: Upstate
1 MW CSP w DADRP and ICAP Loads
Using Upstate ICAP Auction Values
($Thousands/MW)

Revenues	Costs: Low	Costs: Medium	Costs: High
High	46	31	1
Medium	38	23	(7)
Low	11	(4)	(34)

The picture changes more dramatically upstate, where stand-alone ICAP was a money loser even with PON cost sharing. The simplified analysis indicates that if the load acquisition costs are sufficiently low, ICAP combined with DADRP can make money under both high and medium revenue expectations, and remain at least marginal even under low revenue expectations. This profitability is very sensitive to acquisition costs, however. Medium to high revenues are required to produce positive NPVs when the acquisition cost gets to $30/kW, and even high revenues cannot salvage the high acquisition cost ($60/kW) scenario.

Evaluating DADRP as a Bidding Option

The economics of participation in the DADRP program depend on a wide range of complex factors. On the revenue side, the main factors are the characteristics of the customer demand and its flexibility, and the probabilistic characteristics of the day-ahead power and gas prices. On the cost side, the operational procedures that need to be put in place to facilitate participation are important. The costs of these procedures will be different for different types of participants and intermediaries.

In the section that follows, the revenue sides associated with load curtailment (discretionary load) and gas-driven on-site generation applications are explored. The cost side for the participants is highly variable, and depends upon whether the customer achieves a reduction in utility-served load by curtailing or by operating an on-site generator. (In analysis that follows, we will denote on-site generation as DG (for distributed generation)). In modeling the cost side for load curtailment, we assume that the customer includes its outage or lost revenue costs implicitly in setting the strike price at which it will curtail.

For the DG case, evaluating the economics of the investment requires comparing the option value with the full cost, which includes both capital cost and operating costs. We do not in this exploratory evaluation attempt to specify equipment costs and conduct a full investment analysis. Instead, we focus on generating the option value of the DG option (including operating costs), and leave it to another study to ascertain whether the net revenues would serve the debt on the DG system implied by our analysis.

Load Curtailment Option Value

Load curtailment involves reducing electricity usage in a given time period without causing demand to increase at another period. Activities like halting a production process without rescheduling, or reducing lighting or HVAC services are examples of curtailment. *Load shifting* occurs when the customer shifts usage from one period to another in response to either the effective marginal cost of electricity, or to some other inducement (such as those offered by the ICAP/SCR and DADRP programs). When loads are shifted, the costs incurred change dramatically, as they depend upon the cost of make-up power, rather than the outage cost incurred by foregoing a service electricity provides. Such an analysis is beyond the scope of the focus of this study, but deserves attention in subsequent analyses.

The Load Curtailment Options Model

The ability to curtail electricity usage can be viewed as the equivalent to owning a strip of options, one for each time period. An option is the right, but not the obligation, to undertake a market action. In this context, we assume that the customer has entered into a commodity service contract whereby it pays a usage that is not directly tied to the prevailing price, and that contract allows it to consume at any level and pattern it so chooses. The most straightforward example is service under POLR tariff rate comprised of demand and flat energy prices. Since it can vary usage at any time, with no penalty, the customer subscribes to DADRP whereby it may bid to curtail in the NYISO day-ahead market.

The bid involves specifying a quantity to be curtailed, the hours in which it would be curtailed, and the price required to undertake the curtailment. When its curtailment bid is accepted, the customer must either fulfill the curtailment obligation, or face a penalty for failure to do so. The penalty is equal to the real-time LBMP at the time of noncompliance times the level of noncompliance. Thus, the customer can consider itself as having stream of hourly options to curtail available to it. To evaluate that option, the analysis below used conventional options modeling techniques to generate the value of that option under various conditions and bidding strategies.

Option valuation techniques are appropriate for valuing load curtailment capability if the characteristics of the option conform to the models typically used in other markets. An option value is defined as the expected value or payoff where:

Payoff = max [(exercise price – strike price), 0].

The formula expresses the option payoff to be the maximum of 1) the difference between the price received if the option is exercised and the strike price, the amount paid for the option and 2) zero). Typically options are sold, in which case the second result is a loss; the option is never in the money (price never exceeds the strike price) and the net result is a loss in the amount of the option payment. In this application, the price is the amount the customer receives for curtailing, which under DADRP is the day-ahead market price. The strike price is the curtailment bid the DADRP participant submits as its curtailment bid price, which should be at least equal to the cost it would incur if it curtailed. Since customers do not have to pay any fee for the right to bid under DADRP, the option formulation is as specified above, where the outcome is zero if the bid is never accepted.

To value the option, the probabilistic nature of the hourly, day-ahead prices must be characterized as a distribution with known mean and variance. In this analysis, we adopt a somewhat simplistic representation of electricity prices, the Geometric Brownian Motion (GBM) distribution, a constant volatility model. In other words, dispersion in the distribution of hourly is constant over time. The primary reason for adopting the GBM model is that it allows us to use the Black-Scholes option valuation model to value the options. The Black-Scholes model is commonly used by commodity traders to establish a base value for an option, to permit a liquid market for trading the option. (See Appendix 7C for the details of the model.)

In this analysis, each time period in the future is viewed as a separate option and is valued as such. In other words, at each time period in the future the customer has the right but not the obligation to curtail. At each time period, there is a probability distribution of the day-ahead price for that period, and from this one can calculate:

- the probability that the price will be over the strike price (which is discussed below)
- the expected level of payoffs.

The option value of demand reduction flexibility then is the sum of the option values for all the time periods. While the NYISO day-ahead market trades on hourly transactions, for reasons described below the instant analysis employs a longer time period.

To value the option to curtail, one of the key parameters is the strike price at which the option is exercised - the price at which the DADRP participant is willing to curtail if its offer is accepted. When power is curtailed, the customer suffers a reduced level of service, such as reduced lighting of HVAC services levels in commercial buildings or reduced enterprise revenue

because of reduced production, which would be typical of industrial facilities. The monetary value associated that represents the reduced service is embodied in the strike price. Customers should consider all the cost associated with the curtailment and then bid at least that amount.

The cost incurred by customers when service is curtailed is called outage costs. Studies conducted to measure outage costs report values ranging for zero to over $100/kWh. Low outage costs are associated with customers that were easily able to withstand the inconvenience. Residential customers that are not home when the power goes off for a short time only face the nuisance of resetting clocks. Some industrial processes can shut down quickly for short periods with little cost, air-processing facilities being a prime example. Very high outage costs come about when the outage wreaks havoc with the facility, or safety is compromised. Other constraints on a facility also affect outage cost. The duration of the outage can affect outage cost dramatically. Outages that are very short generally result in lower damage costs. But outages of a duration that conforms to business practices also have lower costs, even if they run several hours. That's because it allows the customer to rearrange its operations in a cost-minimizing manner. For example, a two-hour outage might force the customer to pay overtime to meet the day's output requirement. But, if the outage is scheduled for all afternoon, then the customer may be able to alter shift assignments such that additional labor costs are negligible.

A detailed specification of outage costs is beyond the scope of this analysis. However, we are compelled to demonstrate the impact of outage costs on DADRP option value. Therefore, we provide the option values associated with different strike price (outage cost) levels.

Assumptions

Specifying the option model requires six different parameters, each representing some aspect of the customer's cost or market volatility, as follows:

Forward Price Curves: Forward curves are typically developed using the forward prices of power traded in liquid markets. Typically, beyond 18 months the markets are not very liquid—at that point a more robust forecasting model is required, such as a production cost simulation. For this study, we used price simulations by Energy information Agency (EIA) Annual Energy Outlook (AEO) 2002. The standard data sets that are published do not have the on-peak off-peak prices by month. EIA provided us with more detailed results from which we derived the forward curve of on-peak prices. The AEO 2002 forecast of on-peak prices in the New York region are presented in Appendix G.1.1.

Volatilities: Volatilities are typically derived from the prices of options. However, when such prices are not available and/or markets are not liquid, an alternative is to analyze historical prices to characterize the volatilities of future prices. Historical power prices are analyzed to determine the level of volatility for New York as described in Appendix G.1.2. Based on that analysis, we use a Black-Scholes volatility parameter value of 90% for the calculation of the option values.

Strike Price: This is the price at which the customer is willing to undertake a curtailment. as discussed above. For this analysis we used strike prices in the range from $100/MWh to $500/MWh.

Curtailment duration constraints affect the acceptable frequency and duration of curtailments. Different organizations have different constraints on how many hours they can curtail, how much notice they need, and how frequently they can do it. DADRP protocols establish the notice (a day ahead) and frequency (hourly) of pric ing periods. If those are not acceptable, then the customers will not participate. DADRP also allows customers to submit blocked bids that require the curtailment be of a specified length, say four consecutive hours. This prevents avoids a sequence of individual curtailment hours that are separated by one or more non-curtailment hours. Many customers report that such curtailments are the most costly to endure. (Which is why the blocking provision was enacted.) To characterize block bidding, this analysis assumes that bids are submitted for blocks of on-peak hours that accommodate the customer's situation. In addition we specify alternative levels of the monthly maximum hours of curtailment of 20 to 200 hours as a proxy for customers' tolerance or the total number of curtailment it is exposed to.

Interest rate: For option value calculations one needs to use risk-free interest rates. Considering that the forward curves we are using are in real terms (2000 dollars), we need to use risk free real interest rates. The Treasury Yield Curve indicates that the interest rates are about 1.5% for one-year maturity, and about 3% for 5-year maturity. Deducting the inflation rate we used an interest rate of 1%.

Time frame: As described the option value is calculated for the on-peak hours of each month for a five-year period. This approach gives a lower bound to the option value since it corresponds to a flexibility level where the customer accepts the average on-peak price

for its curtailment. Customers that can turn equipment on and off every hour can generate greater value for that enhanced optionality than our results produce.

Curtailment Option Value Simulation Results

The results for option values for curtailment are presented in Table 7-6.. A curtailment level of 200 hours corresponds to a customer with a very high level of flexibility; the customer can curtail about 10 hours each of the 20 weekdays of the month. Table 7-6 shows that for a customer with that level of flexibility, and a strike price of $0.10/kWh, the revenue generated from participating in the day-ahead market will be $139,000 for the 5-year period. This value reduces to $42,000 for a strike price of $0.50/kWh.[7]

The strike price is assumed to reflect the bidder's entire variable operating expenses and/or revenue losses. The option value calculated can also be adjusted to account for the initial investment (e.g. in control equipment installed to facilitate the curtailment) needed to enable participation, and the NPV of any operating expenses. (See *Inclusion of DADRP in the CSP Business Case*, above.)

Table 7-6. Option Value of Curtailment for 5 Years of Operation (thousand $/MW)

Monthly Limit (hours)	Strike Price ($/kWh)				
	0.10	0.20	0.30	0.40	0.50
20	14	9	6	5	4
100	70	44	32	25	21
200	139	87	64	50	42

Assumptions: Price volatility of on-peak power = 90%
Risk-free real interest rate = 1%
All prices in year 2000 dollars.

[7] Even though the higher strike price produces more revenue for each hour in which these loads are scheduled, the number of hours scheduled falls proportionally greater and as a result total revenue declines.

Distributed Generation Option Value

The DG units considered in this section are assumed to be fueled by natural gas. (We have not considered diesel generators since they do not currently qualify to participate to the DADRP program.)

DG Model

Owning a natural gas generator is equivalent to owning a strip of spread options, one for each time period. Option value is the expected value of payoff where

Payoff = max [power price - (HR*gas price + variable O&M), 0]

The above expression can also be separated into marginal revenue (MR) and marginal cost (MC). Power price is MR, and the term in parentheses is MC. Whenever the MR exceeds MC, generators are run (provided there are no other operational constraints).

To value the option, the probabilistic nature of the power prices and gas prices needs to be characterized. In this preliminary work, we used rather a simplistic model where the spread (power price – HR*gas price) is assumed to be distributed normally. Volatility is not the standard Black-Scholes volatility; it is the absolute volatility of the spread (see Appendix 7.B for the details of the model).

Every time period is a separate option. Total value of the generation optionality is the sum of these option values throughout the lifetime of the equipment. As was invoked above, the value is determined for a five-year period, which is shorter than the typical lifetime of natural gas driven generators. However, the uncertainty in price forecasts beyond years militates using an abbreviated lifetime to evaluate the investment.

The strike price is mainly the variable operating costs for running the equipment. The other important factor in valuing the distributed generation option is the Heat Rate (HR) of the equipment.

The fixed O&M is not part of the strike price. Such costs are bundled with the investment costs and compared to the option value in order to qualify the technology as economic or not.

DG Assumptions

The important differences in this model are with regard to the specification of the forward curve and volatility, how strike prices are set, and constraints on curtailment bidding imposed by environmental regulations. These are described below.

Forward Curve: Gas forward curve is from taken from the 2002 New York State Energy Plan and is presented in Appendix G.1.1. The model uses monthly values but the gas price data is annual. If and when a forecast of monthly-prices is available, that needs to replace the numbers used here.

Volatility: The absolute volatility of power-gas price spread is developed from historical price data in Appendix G.1.2. In this analysis an annualized value of $80/MWh is used.

Strike Prices (Variable O&M): Typical values for variable O&M costs for gas driven technologies are around $7/MWh. We present results for values close to this number.

Heat Rate (HR): A heat rate of 11400 Btu/kWh is assumed. This corresponds to 30% efficiency that is representative of the more efficient micro-turbines.

Customer constraints on frequency and duration of DG operation: Different organizations have different constraints on how many hours they can run generators, and how frequently they can do it usually depending on environmental regulations. In this study, we evaluated monthly maximum hours of generation at intervals between 20 to 200 hours as a proxy for environmental and other constraints.

Interest rate: As was the case above, we used a real interest rate of 1%.

Time frame: The values given in the results section are the sum of the monthly peak period option values for 5 years of operation.

DG Option Simulation Results

The option values simulated for gas-driven distributed generation are presented in Table 7.3.2. The values are comparable to the costs of installing some classes of gas driven technologies (such as micro-turbines). These results indicate that, where constraints permit operating close to 200 hours/month, natural-gas driven technologies such as micro-turbines may be feasible. The revenues generated would still not support fuel cell technologies at current technology costs.

Table 7-7. Option Value of Gas Driven Distributed Generation for 5 Years

of Operation (thousand $/MW)			
Monthly DG Dispatch Limit (hours)	**Variable O&M ($/MWh)**		
	4	**7**	**10**
20	**52**	**51**	**49**
100	**262**	**254**	**246**
200	**524**	**507**	**491**

Assumptions: (a) Spread volatility (absolute) $80/MWh; (b) Risk-free real interest rate = 1%; (c) Prices in Year 2000 dollars; (d) Heat Rate = 11,400

Future Work

Improvements in ICAP/EDRP modeling: In the preceding sections we evaluated the ICAP/EDRP opportunities using historical event data. ICAP/EDRP events are mainly driven by the level of reserves. Ideally we would look at historical reserve data and also historical events and come up with a probabilistic model for the ICAP/EDRP occurrences. Since in these programs the payment to the customers is also a function of the real-time prices, we need to model the real-time LBMPs together with the events with the appropriate correlation. The valuation model can be constructed as a Monte-Carlo simulation model. Events and prices are generated using the event process and the results for a large number of simulations constitute the output of the model. The mean value of the cash flow is the forecasted value of participation.

Required Improvements in DADRP Modeling: The forward curves and volatilities used in this model need to be improved to put this analysis in line with what the more sophisticated companies are doing in the market. Forward curves used here may not be in line with the traded forward prices.

In reality, volatilities are not constant as assumed here, thus rendering the results of the Black-Scholes model speculative. Models need to be developed to reflect the seasonality of volatility. Also, the volatilities need to be in line with the prices of traded options. Also, the introduction of hourly volatilities will better estimate the true value of hourly flexibility, and evaluate alternative curtailment strategies.

Modeling displacement together with curtailment (discretionary load) and DG: In this report we covered curtailment and DG. Another important type of demand response is

displacement where the customer shifts the time of energy use without reducing the overall volume. To value this type of response one needs to model the power-price spread between on-peak and off-peak.

Modeling Intermediaries: The value added by intermediaries can be modeled, and in some cases quantified. For example, the addition of controls leads to greater hourly flexibility and therefore increases the option value. Other entities can provide risk management services that complement a curtailment strategy and produce greater profits.

Customer Modeling: The customer constraints will have a great influence on the value once the hourly valuation is introduced. Many organizations have complex operational constraints and they may use optimization techniques to extract the most value given their constraints. Similar optimization techniques need to be utilized in the valuation model.

Table 7-1A Subscribed and actual performance by 2002 NYSERDA PON participants

Summer 2002 Events Only & NYSERDA 2002				
	All EDRP Subscribers			
	Overall Total Number of EDRP Subscribers	Total Pledged Hourly MW Reduction	Total Average Hourly MWH Performance	Wgt. Performance Ratio
Non-NYSERDA	1,407	1,254.7	552.6	0.44
Peak-Load Only	118	31.5	1.5	0.05
Enabl. Tech Only	183	186.7	110.3	0.59
Both	3	5.5	4.5	0.81
Totals	**1,711**	**1,478.3**	**668.8**	

	Subset of All EDRP Subscribers with positive EDRP Performance							
	Number of Customers	% of Total Analyzed	Total Pledged Hourly MW Reduction	% of Total Analyzed	Total Average Hourly MWH Performance	Wgt. Performance Ratio	Total Summer 2001 MW Performance	Total Summer 2002 Program NYISO Payments
Non-NYSERDA	1,168	83%	1,071.5	85%	552.6	0.51	5,448.8	$2,724,381
Peak-Load Only	18	15%	5.6	18%	1.5	0.27	14.9	$7,474
Enabl. Tech Only	128	70%	169.4	91%	110.3	0.65	1,102.9	$551,440
Both	3	100%	5.5	100%	4.5	0.81	44.7	$22,329
Totals	**1,317**	**77%**	**1,252.0**	**85%**	**668.8**		**6,611.2**	**$3,305,622**

Table 7-1B Subscribed and actual performance by NYSERDA PON participants who re-enrolled from 2001 or enrolled in Summer 2002

	All EDRP Subscribers			
	Overall Total Number of EDRP Subscribers	Total Pledged Hourly MW Reduction	Total Average Hourly MWH Performance	Wgt. Performance Ratio
Non-NYSERDA	1,370	1,168.4	493.2	0.42
Peak-Load Only	146	102.5	51.9	0.51
Enabl. Tech Only	185	187.8	110.9	0.59
Both	10	19.7	12.8	0.65
Totals	**1,711**	**1,478.3**	**668.8**	

	Subset of All EDRP Subscribers with positive EDRP Performance - Cumulative							
	Number of Customers	% of Total Analyzed	Total Pledged Hourly MW Reduction	% of Total Analyzed	Total Average Hourly MWH Performance	Wgt. Performance Ratio	Total Summer 2001 MW Performance	Total Summer 2002 Program NYISO Payments
Non-NYSERDA	1,138	83%	988.6	85%	493.2	0.50	4,855.0	$2,427,479
Peak-Load Only	40	27%	73.4	72%	51.9	0.71	518.8	$259,377
Enabl. Tech Only	130	70%	170.5	91%	110.9	0.65	1,109.3	$554,673
Both	9	90%	19.5	99%	12.8	0.66	128.2	$64,093
Totals	**1,317**	**77%**	**1,252.0**	**85%**	**668.8**		**6,611.2**	**$3,305,622**

Appendix 7B – Market Maker Survey Instrument

BACKGROUND

Neenan Associates has been asked by New York State Energy Research and Development Authority (NYSERDA) to help it develop programs to promote participation in demand response programs. The survey that follows was designed to collect information on the relative preferences for alternative NYSERDA programs by entities, like yourself, that are or might provide demand response program services.

NYSERDA administers the New York State electric system benefits fund to promote economic growth in the state through the wise and effective use of electricity. These programs include investments in conservation devices, alternative generating technologies, and more recently in promoting demand response program participation. NYSERDA's focus in the past two years has been on increasing participation in the demand response programs implemented by the New York Independent System Operator (NYISO).

NYSERDA desires to understand how demand response contributes to the business goals of firms that are either currently involved in implementing such programs in New York, or that are or might be considering involvement in the near future. More specifically, NYSERDA desires to identify and characterize the factors that these entities indicate are critical to their sustained involvement in demand response programs in New York so it can better tailor its programs to these needs.

Neenan Associates will treat all information provided by respondents as strictly confidential, including the identity of the respondents. The information received will be used in summary form, or as non-attributed specific responses, to advise NYSERDA on how it can design programs that are attractive to a variety of demand response providers.

Please complete the attached survey and return it to:

Bernie Neenan

Neenan Associates

Tel. 315.478.9974
Fax 315.478.9982

Email bneenan@bneenan.com

If you'd like to complete the survey over the phone, or discuss the survey and NYSERDA programs further, please call Bernie Neenan at the number provided above.

Thanks for taking time to help NYSERDA design effective demand response programs.

Survey respondent (individual): _____

Entity (business)_____Date_____

Phone # _____ email _____

INFORMATION YOU PROVIDE WIL BE HELD CONFIDENTIAL AND CONVEYED IN SUMMARY FORM OR WITHOUT ATTRIBUTION TO THE RESPONDANT

Section 1.0 Business Characterization

Q 1.1. Which of the following best describes your primary business activity (check one)?

” **Regulated (POLR) commodity provider**

” **Competitive commodity provider**

” **Curtailment service provider (no commodity or wires services)**

” **Electricity wholesale trading and financial services**

” **Information technology equipment/service provider**

” **Controls technology equipment/service provider**

” **Performance ESCO**

” **Other (Please specify)_____**

Q 1.2. What hurdle rate does your firm require for investments in new business lines?

” ROI (%) _____percent

” Payback _____years

Q 1.3. Which of the following best describes how you see demand response contributing to your business objectives (check one)?

” Specialize in demand response, as a curtailment service provider

” Complement to commodity service business

” Complement to wires services business

” Complement to control technologies business

” Complement to information technologies business

” Other (Please specify)_____

Q 1.4. What do you see as the primary barriers to achieving your goal with regard to demand response (list in order of importance)?

1st._____
_____
_____
2nd._____
_____
___
3rd._____
_____
___

Q 1.5 Should regulators or state policy makers direct public benefit funds to promote demand response? Please elaborate on your choice.

Yes._____

No._____

Q 1.6 Which of the following best describes you view on how demand response programs should be administered (please check one)?

- **ISOs should design and administer demand response programs directly to retail customers**
- **ISOs should offer demand response programs but only through POLR and competitive retailers**
- **ISOs should not be involved in demand response programs that should be left to competitive entities**

Please provide comments to support your choice

_____

_____

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Section 2.0. Experience with Demand Response Programs

Q 2.1. Was your firm involved with the designing or implementing load management programs *prior to 1998*? If so, please indicate your involvement for those you indicate yes in the adjacent columns.

Load Control Program Involvement Prior to 1998						
Yes or no	**Sector**	**Type (see key)**	**State**	**Design (see key)**	**Implement-ation (see key)**	**Enabling Technology (see key)**
	Residential					
	Commercial					
	Industrial					

Key for Type (select the one that best describes the program):

Utility sponsored **DLC** = direct load control

Utility sponsored **LC** = Load curtailment

Utility sponsored **RTP** = Real-time pricing

Other = O (describe) _____

Key for Design - includes setting program features and preparing and filing tariffs of other authorizations.

Key for Implementation - recruitment of participants, billing and other customer services.

Key for Enabling Technology - supplying and/or installing meters, meter reading and visualization equipment, load control technologies

Q 2.2. Which of the following best describes why you implemented a demand response program?

- **Avoid peak capacity investment**
- **Prevent uneconomic bypass/cogeneration investments**
- **Load profile reshaping**
- **Promote expanded electricity usage**
- **Other (specify) _____**

Q 2.3. What was the highest level of participation you realized?

Sector	Number of Participants	Curtailable MW
Residential		
Commercial		
Industrial		

Q 2.4. Is the program (are the programs) still in operation?

- **YES**

NO - why was it (were they) eliminated?

_____

Q 2.5. Was your firm involved with ISO-based load management program *outside of New York State? If so, please* Indicate your involvement for those you indicate yes.

Involvement in ISO Program in CA, TX, PJM or ISO-NE						
Yes or no	**Sector**	**Type (see key)**	**State**	**Design**	**Implement-ation**	**Enabling Technology**
	Residential					
	Commercial					
	Industrial					

Key for Type (select the one that best describes the program):

ISO sponsored capacity program = **ICAP**

ISO sponsored emergency program = **Emergency**

ISO sponsored energy bid or load following program = Energy

Key for Design - includes setting program features and preparing and filing tariffs of other authorizations.

Key for Implementation - recruitment of participants, billing and other customer services.

Key for Enabling Technology - supplying and/or installing meters, meter reading and visualization equipment, load control technologies

Q 2.6. What was the highest level of participation you realized in that ISO-based program?

Program Type	Number of Participants	Curtailable MW
ICAP		
Emergency		
Energy		

Q 2.7. Has your firm been involved with price-responsive load programs implemented by NYISO ? *If so, please* Indicate your involvement for those you indicate yes.

Involvement with NYISO-based Programs						
Yes or no	**Sector**	**Type (see key)**	**State**	**Design**	**Implement-ation**	**Enabling Technology**
	Residential					
	Commercial					
	Industrial					

Key for Type (select the one that best describes the program):

ISO sponsored capacity program= **ICAP**

ISO sponsored emergency program = **Emergency**

ISO sponsored energy bid or load following program = **Energy**

Section 3.0. Relative Preferences for Alternative Program Initiatives

NYSERDA funds program initiatives through Program Opportunity Notices (PONs). It currently is evaluating the effectiveness, in attracting the participation of firms like yours, of PON initiatives directed at the various stages of the demand response business structure.

In the table below, please rank the value to your business of funding directed at each of the listed PON Initiatives. A score of 1 indicates little or no value to your business model, and value of 6 indicates a very high value. If there is a specific activity listed in the examples, or that you have identified, that stand outs as being especially useful to you, please so indicate in the Comments column.

Table 1. Alternative Programs to Support Demand Response

Stage	PON Initiative	Examples	Value 1-6: 1 (low), (high)	Comments (add'l space at the end of the document)
1	General Concept Promotion and Education	• Generic brochures • Briefings, workshops • Testimonials, Case Studies		
2	Individual customer Assessment and Training	• Self-administered workbook • Tailored, on-site audit • Web-based, interactive audit		
3	Marketing and Subscription	• Sales goals incentives • Sales materials budget		
4	Essential Technology	• Meter acquisition • Meter installation • Meter reading		
5	Enabling Technology	• Event Communications • Meter gateway • Web-based meter access		
6	Program Administration	• Billing systems or services		
7	Performance Benefits	• Augment NYISO payment levels • Guaranteed # curtailment opportunities each year • Cover noncompliance penalties		
8	Other-specify			
9	Other-specify			

Section 4.0. Relative Preferences for Alternative Program Initiatives

In the table below, for each Stage and PON initiative, please indicate the Percentage Funding you would like to see devoted to the indicated PON Initiative.

Table 2. Allocation of PON Funding to Best Promote Demand Response for Your Business Model			
Stage	**PON Initiative**	**Percentage Funding PON Initiative**	**Comments**
1	**General Promotion and Education**		
2	**Individual customer Assessment and consulting**		
3	**Marketing and Subscription**		
4	**Essential technology**		
5	**Enabling technology**		
6	**Program Administration**		
7	**Augment Performance Benefits**		
8	**Other-specify**		
9	**Other- specify**		
	TOTAL	**100%**	

Section 5. Comments

Q. 5.1 Do you have additional comments or recommendations you would like brought to NYSERDA's attention? If so, please write them out in the space below. Comments and suggestions will be conveyed to NYSERDA and others without attribution.

Comments and suggestions

_____

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Thanks again for taking time to help NYSERDA design effective demand response programs.

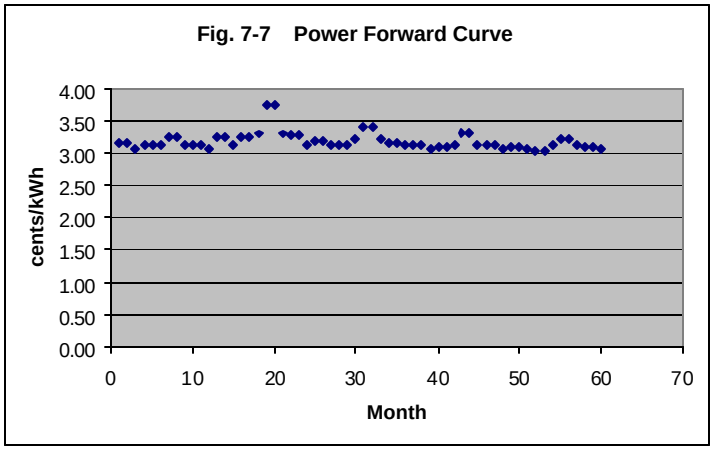
Appendix 7C: Business Case Models

Energy Price Modeling

Forward Prices

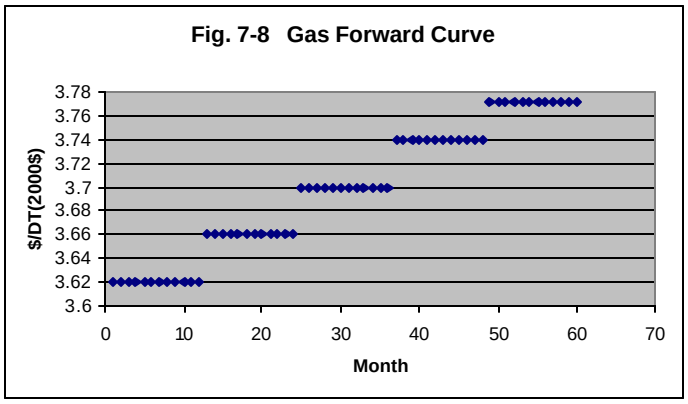
Forecast of Power Prices

The power price forward view was developed using results from AEO2002, which and are shown in Fig. 7-7.



Forecast of Natural-gas Prices

Gas price forward view is derived from the 2002 New York State Energy Plan and is shown in Fig. 7-8.



Price Modeling

Analysis of Historical Prices: Determination of Power Price Volatility

We compiled and analyzed the historical day-ahead prices for NYISO. Fig. 7-9 shows the day-ahead prices. Fig. 7-10 shows the level and seasonal nature of price volatility that needs to be represented the price model. The volatilities shown in this figure are the standard deviations of daily price returns. For each day the daily price return is:

SD of Returns = {[price(t+1)-price(t)]/price(t)}.

= {ln(price(t+1)/price(t)}

The standard deviation of such returns for days from 15 days before to 15 days after gives the 30-day rolling price volatility.

Black-Scholes model assumes that the volatility is constant over time. The figure in this page clearly shows that the volatility does not stay constant over time; it exhibits as distinct seasonal pattern and perhaps a subtler day-type pattern. However, it appears that the level of the volatilities in spring and summer months have been coming down, and during calmer seasons the volatilities have been around 90%. Based on this chart we used a longer-term volatility of 90%. This gives a conservative value for the options considered. Higher volatilities generate higher option values.

Fig. 7-9 Historical Day-Ahead On-Peak Prices for Power

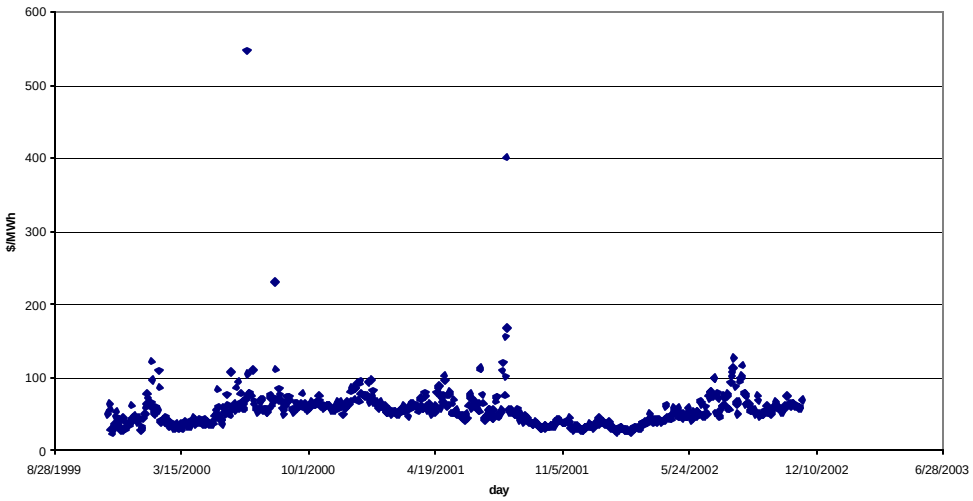


Fig. 7-10 30-day Rolling Annualized On-Peak Volitility for Power

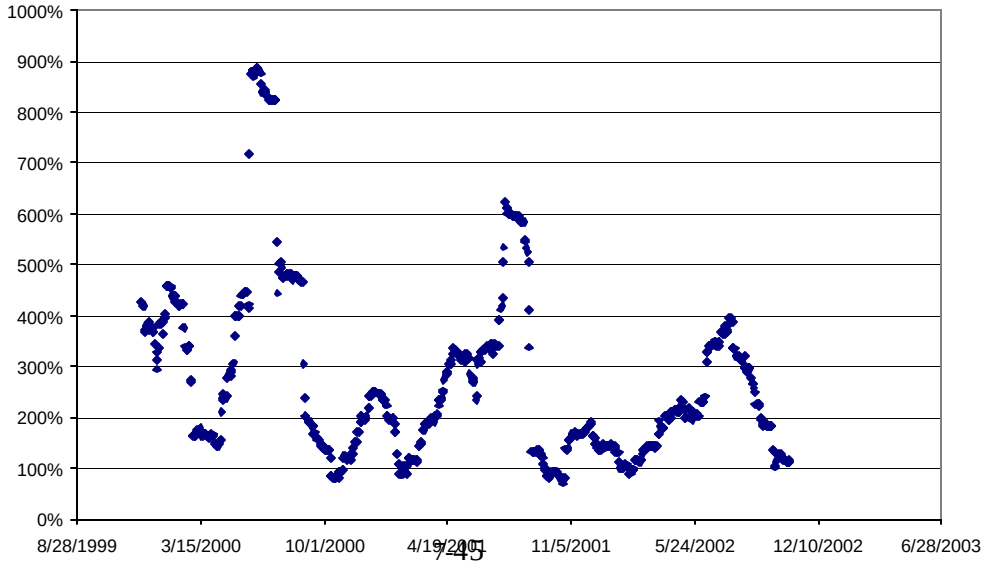
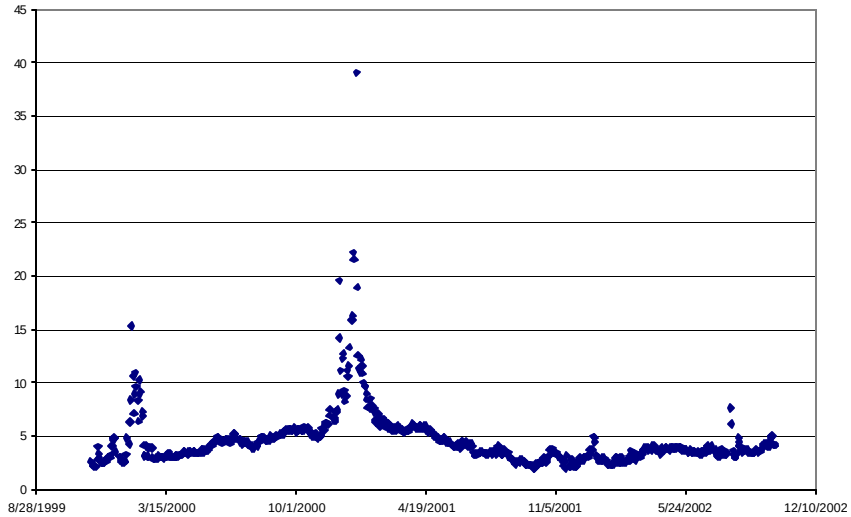


Fig. 7-11 shows the historical gas prices in the New York area.

Fig. 7-11 Historical Gas_Daily Natural Gas Price Index (Transco Zone 6, NY)



In some modeling approaches, we use the distribution of the spread between power and gas prices directly. Fig. 7-12 shows the historical spread values.

Fig. 7-13 shows the volatility of the spread. It is the absolute volatility of the spread. In other words, it is the standard deviation of [spread(t+1) – spread(t)].

Fig. 7-12 Historical Spread between Power and Gas Prices

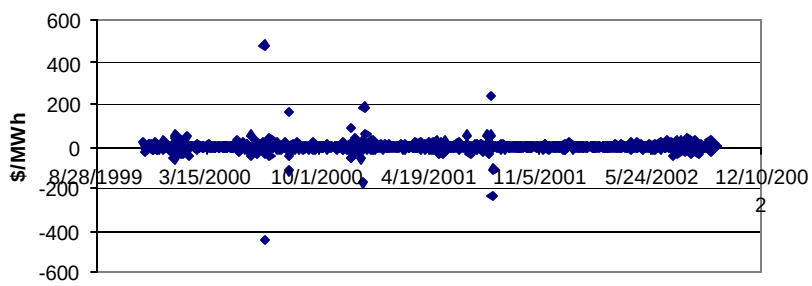
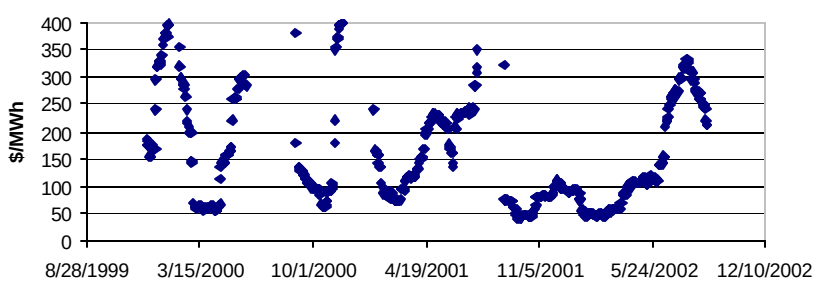


Fig. 7-13 30-day Rolling Annualized Absolute Volatility of Spread



Option Pricing Models

Load Curtailment Options Model

$$Option\ Value_t = e^{-rt}[P_t\ N(d) + Strike\ N(d - s\sqrt{t})]$$

$$d = \frac{\ln(P_t / Strike) + 0.5\, s^2\ t}{s\sqrt{t}}$$

$$P_t = forward\ \ price\ of\ \ power$$

$$r = risk\ \ free\ discount\ \ rate$$

$$s\ = Black - Scholes\ volatility$$

$$Strike = strike\ price$$

$$N(.) = normal\ \ distribution\ \ function$$

Distributed Generation Options Model

$$Option\ Value_t = e^{-rt}[(P_t - HR * G_t - Strike)N(d) + s\sqrt{t}\ n(d)]$$

$$d = \frac{P_t - HR * G_t - Strike}{s\sqrt{t}}$$

$$P_t = forward\ \ price\ of\ \ power$$

$$G_t = forward\ \ price\ of\ \ gas$$

$$HR = heat\ rate$$

$$r = risk\ \ free\ discount\ \ rate$$

$$s\ = absolute\ volatility$$

$$Strike = \text{var}\,iable\ O\&M$$

$$N(.) = normal\ \ distribution\ \ function$$

$$n(.) = normal\ \ density\ \ function$$

Glossary of Acronyms

CBL – Customer Baseline Load

CERTS - Consortium for Electric Reliability Technology Solutions

CSP – Curtailment Service Provider

DADRP – Day-Ahead Demand Response Program

DAM – Day-Ahead (Electricity) Market

DG – Distributed Generation

DOE – Department of Energy

DR – Demand Response

DVD – Digital Video Disk

EDRP – Emergency Demand Response Program

EIS – Energy Information System

EMCS – Energy Management and Control System

ESCO – Energy Service Company

FERC – Federal Energy Regulatory Commission

FTE – Full-Time Employee

HR – Heat Rate

HVAC – Heating, Ventilation, and Air Conditioning

ICAP – Installed Capacity

ICAP/SCR – Installed Capacity Special Case Resource program

INP – Informed Non-Participant

IOU – Investor-owned Utility

ISO – Independent System Operator

kW - Kilowatt

kWh – Kilowatt-Hour

LBMP – Location-Based Marginal Price

LBNL - Lawrence Berkeley National Laboratory

LIPA – Long Island Power Authority

LOLP – Loss of Load Probability

LSE – Load Serving Entity

MC – Marginal Cost

MR – Marginal Revenue

MW – Megawatt

MWh – Megawatt-Hour

NPV – Net Present Value

NYISO – New York Independent System Operator

NYPA – New York Power Authority

NYSDPS – New York State Department of Public Service

NYSPSC – New York State Public Service Commission

NYSERDA – New York State Energy Research and Development Authority

PNNL - Pacific Northwest National Laboratory

POLR – Provider of Last Resort

PON – Program Opportunity Notice

PPI – Peak Performance Index

PRL – Price Responsive Load

RIP – Responsible Interface Party

ROI – Return on Investment

RTM – Real-Time (Electricity) Market

RTP – Real-Time Pricing

SCD – Security Constrained Dispatch

SCUC – Security Constrained Unit Commitment

SD – Standard Deviation

SIC – Standard Industrial Classification

SPI – Subscribed Performance Index

TO – Transmission Owner

TOU – Time of Use

VEUE – Value of Expected Un-served Energy

VIPP – Voluntary Interruptible Power Program

VMP – Value of the Marginal Product

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