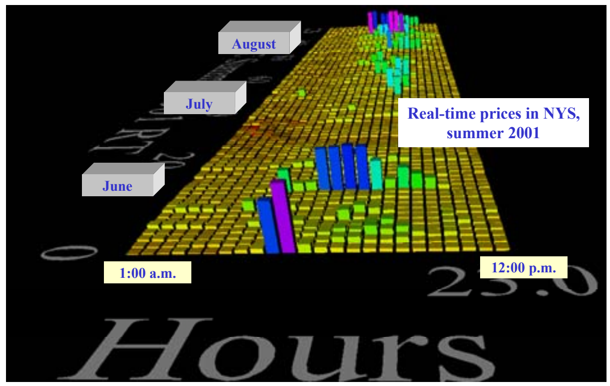
Executive Summary

Background

This past summer, the New York Independent System Operator (NYISO) launched a price-responsive load (PRL) pilot program to enable the state's end-use customers to become more involved in electricity markets. The potential improvements to market performance from exposing wholesale transactions to retail price responsiveness had been well documented, especially in situations where the possibility for capacity shortfalls, and resulting high prices, is uncomfortably high. A price topology that exhibits high prices only periodically, as illustrated, is conducive to programs that direct customers to curtail or shift load under very specific conditions determined by the NYISO, to ensure that the maximum market benefits are realized



Designing and implementing PRL programs that would be effective in a newly chartered wholesale market proved to be a difficult undertaking in the fall of 2000. Data to characterize and quantify the potential impacts, and trace their distribution among stakeholders, was in short supply since the market was only a year old. Moreover, there was little foundation for characterizing how customers would value and respond to opportunities to adjust their electricity usage patterns in response to highly volatile wholesale electricity prices. Legacy load management programs were designed to meet very different objectives, and as a result it was a stretch to extrapolate the results of past interruptible and curtailable programs to competitive market circumstances.[1]

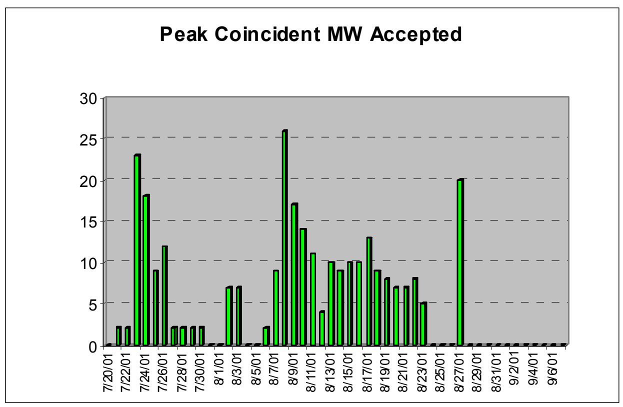
Given these circumstances, NYISO's Market Members elected to implement a pilot in the summer of 2001 with the specific goal of resolving these fundamental uncertainties. The NYISO's Market Participants and other stakeholders participated in a collaborative process to design PRL programs that would appeal to a wide range of customer circumstances, and thereby provide empirical data to support the evaluation of how and why customers did or did not

[1] Despite the almost universal availability of interruptible and curtailable load programs for the past 20 years, very little data are publically available to support research into the performance of different program designs, or to characterize Participants' price elasticities.

participate. These programs reflect the basic principle that was adopted to ensure that customer load management actions enhanced the market's performance: equal pay for equal performance. In other words, PRL resources should be fully integrated into the NYISO's market operations, thereby justifying being paid curtailment benefits that reflect market-clearing transactions.

Two PRL programs were launched, one in each of the last-priced auction energy markets the NYISO operates. The Emergency Demand Response Program (EDRP) was intended to provide a stock of dispatchable resources that would be available to bolster reserves during times of system emergency. The NYISO provides Participants at least two hours advance notice of when curtailments are needed to supplement conventional generation resources, and those that curtail during the specified periods are paid the location-based marginal price (LBMP) or $500/MWH, whichever is higher. Last summer, the EDRP program proved its worth, supplying over 425 MW of load reduction when it was most needed.

A companion (PRL) program, the Day-Ahead Demand Response Program (DADRP), extends to retail customers access to the NYISO's day-ahead electricity market. Participants submit demand reduction bids comparable to supply bids of generators and receive market prices for load reductions scheduled for the next day. They settle any curtailment shortfalls at the higher of the day-ahead or real-time market price, plus a 10% penalty. Over a dozen customers subscribed to this adaptation of the real-time pricing principle to wholesale energy markets, providing over 25 MW of load reduction coincident with peak summer prices.[2]



Customers with at least 100 kW of curtailable load were allowed to participate in one or both PRL programs.[3] In addition, 40% percent of PRL subscribers chose to also participate in an existing NYISO load management program. The NYISO allows Load Serving Entities (LSEs) to claim curtailable special case load resources (SCR) to fulfill their installed capacity (ICAP) requirements. Customers that qualify their load curtailment capability can sell their ICAP/SCR

[2] In conventional retail real-time pricing programs, customers respond to posted market-clearing prices, which do not directly take into account the possible price response. DADRP curtailment bids by end-use customers are offered in advance and fully integrated in the price setting mechanics, thereby insuring that they exercise influence over the level of prices all customers face.

[3] To supplement or fulfill their EDRP curtailment intentions or obligations, customers may use on-site backup generation. However, only non-diesel generators are allowed to participate in the DADRP program.

capacity, which generates a stream of benefits. The NYISO exercises its demand call on ICAP/SCR during periods of reserve shortfalls.[4] Participation in ICAP/SCR offers up-front payments that PRL programs do not, which appeals to many customers in spite of the penalties assessed for noncompliance. Since PRL curtailments called under EDRP and ICAP/SCR demand calls were mostly coincident last summer, it was not possible to separately estimate the PRL and ICAP/SCR program impacts.

To assess their performance during the summer of 2001, the NYISO engaged Neenan Associates to conduct a comprehensive evaluation of these programs. That analysis involved two interrelated initiatives. The first involved quantifying the impact of EDRP and DADRP curtailments and on-site generation dispatch on system reliability and on the NYISO's day-ahead market (DAM) and real-time market (RTM) prices. The second involved evaluating responses to surveys administered to customers and to the entities that marketed the PRL programs to identify ways to improve program participation and performance.

To conduct the market evaluation, it was necessary to simulate what market prices would have been had the programs not been in place. Short-run supply curves were estimated for both the DAM and RTM, by NYISO pricing zone, specifically for purposes of this evaluation, and to provide a means for managing the PRL program design and implementation in the future. The supply analysis provides the basis for quantifying the benefits of participation by customers, but does not explain why or how they participated.

Direct customer feedback about both EDRP and DADRP was obtained through a survey administered to a sample of program Participants and non-Participants, the latter representing customers that were contacted about subscription, but declined. Survey questions were designed to garner information important to determining customer satisfaction and to identify important barriers to participation. In addition, the survey solicited information that would help characterize factors that explained customers' participation. The analysis of these revealed preferences provides insight into why customers participated in the current programs, and it will help LSEs and CSPs retain current Participants and recruit new ones. Through a conjoint survey, customers were asked about their preferences for alternative program designs. The analyses of these stated preferences supports recommendations for changes in program features that would extend participation to a broader variety of customers.

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[4] Customers participating in both ICAP/SCR and PRL programs receive PRL benefits only when the NYISO coincidently call for curtailments under both programs.

Finally, a survey was administered to the Load Serving Entities (LSE) and Curtailment Service Providers (CSPs) that marketed the PRL programs to customers.[5] The goal was to characterize how well the programs met their enterprise objectives and their customers' expectations and needs. These entities were also asked to grade the performance of the NYISO, the Department of Public Service (DPS), and the New York State Energy Research and Development Agency (NYSERDA) in creating an environment conducive to designing and implementing successful PRL programs.

Given that electricity demand in New York State during two consecutive days in August of 2001 surpassed the previous all-time peak by over 2%, it is difficult to imagine more appropriate circumstances under which to assess the performance of these PRL programs. From the variety of evidence provided below, it is clear that EDRP did contribute importantly to restoring the security of New York's bulk power system during emergency situations, as well as provide other benefits to the real-time electricity market. When one is reminded that EDRP had been in operation for only about two months when the emergency events were called, the success of the program is perhaps even more remarkable, and it reflects the effectiveness of the overall program design and the NYISO's commitment to its implementation.

The next section describes the impact of PRL programs and provides estimates of the market value of these programs. The following section describes the analysis of customer expectations for and satisfaction with the programs that were implemented last summer, based on their response to a survey, and characterizes and quantifies Participants' response to curtailment opportunities that became available. This is followed by an evaluation of the performance of the NYISO and two supporting state agencies, as seen from the perspective of the LSEs and CSPs that marketed the PRL programs to end use customers.

An Examination of Operation of the Emergency Demand Response Program

At the time the EDRP events of August 7-10, 2001 were called, 292 customers were enrolled in EDRP. As the adjacent table shows, about 72% subscribed to the program through a LSE, while a quarter subscribed through a CSP. The others were direct serve customers with the NYISO. Participants

EDRP Participants by Subscriber and Zone

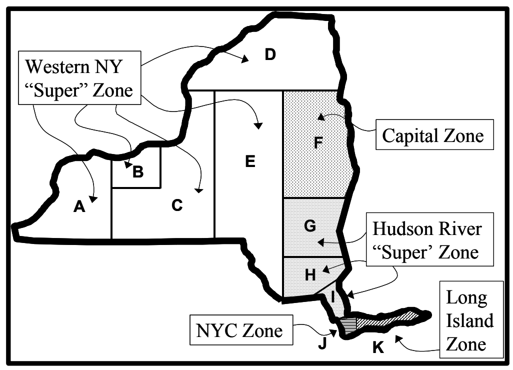
Zone	LSE	CSP	Other	Total No.	Total %
West	33	1	4	38	13%
Genesee	16	0	0	16	5%
Central	29	0	2	31	11%
North	5	0	0	5	2%
Mohawk Valley	23	0	0	23	8%
Capital	23	1	4	28	10%
Hudson Valley	13	2	0	15	5%
Millwood	4	6	0	10	3%
Dunwoodie	15	5	0	20	7%
NYC & LI	49	57	0	106	36%
Totals	210	72	10	292	100%
% of Total	72%	25%	3%		

[5] CSPs are entities that market unbundled PRL service to customers that take wires and commodity services from another entity, or other entities.

were recruited from throughout the State. Over the 23 EDRP event hours, the EDRP Participants delivered a total of 8,159 MWH of EDRP load. Nearly 94% of it was delivered during the first three event days, reflecting the fact that western pricing zones (the first five zones in the table above), which contain the largest share of enrolled Participants, were not asked to curtail during the final EDRP event day.

<u>EDRP Load Reduction Performance</u>.

To facilitate the estimation of the short-run electricity supply curves needed for market impact evaluation, three of the NYISO pricing zones were modeled individually. The other zones were combined into two "super" zones, the Western NY and Hudson River, as illustrated in the accompanying figure.



The 39% of EDRP Participants whose premises are located in the western super zones provided a disproportionate 65% of the total EDRP load curtailment during the four event days, despite the fact that curtailment opportunities were available to these customers on only the first three of those days, for a total of 18 hours. An additional day with five hours of curtailment was available to all other Participants.[6] The EDRP Participants (10%) in the Capital zone also contributed disproportionately more, providing 18% of total curtailments. Participants in New York, Long Island, and the Hudson Region, contributed proportionately less.

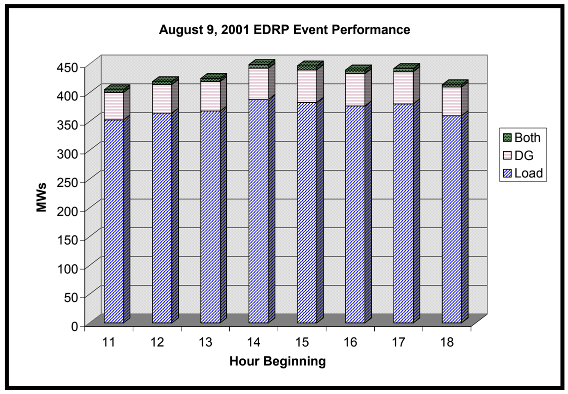
Impact of EDRP on Real-Time Zonal Loads			
	Average Hourly Event Value		
Zone	EDRP load (MWH)	% Change in RT Load due to EDRP	Total EDRP Load (MWH)
Capital	63	3.1%	1,446
New York	37	0.4%	860
Long Island	6	0.1%	148
Western New York	293	3.3%	5,276
Hudson Region	19	0.5%	430
Grand Total			8,159

In percentage terms, in both the Capital zone and the Western New York region EDRP load reduction constituted just over 3% of actual load served during the event hours (see the adjacent table). In the other three study regions, the EDRP load accounted for no more than half of one percent of actual load served. About 85% of the EDRP curtailment performance came from Participants that responded solely by reducing their load.

[6] EDRP resources are dispatched by the NYISO when and where it anticipates operating reserve shortfalls. At times, load pockets arising from transmission constraints necessitate evaluating regional needs and dispatching EDRP curtailments accordingly. This was the case on August 10th.

Participants supplied the remaining 15% of load relief either by dispatching on-site generation, or both curtailing usage and deploying a generator.

Viewed from an hour-by-hour perspective, the PRL resources provided a very reliable and predictable, and therefore valuable, resource. Participants delivered an average hourly load reduction of 420 MW over the first three event days. On the fourth day, the average dropped to 118 MW per hour because Western New York Participants were not included in the curtailment call. With the exception of one hour during the first three event days, the hourly EDRP load reduction statewide was never above or below the average contribution by more than 5%. An example of this persistence for August 9, the third event day, is portrayed in the adjacent graphic. Somewhat surprisingly, customers reducing load demonstrated greater persistence than those that responded by dispatching on-site generation.[7]



The *persistence* of load curtailments throughout the event hours and across consecutive days runs counter to conventional wisdom, and it is perhaps more remarkable than the level of performance itself. Many customers facing day after day of curtailments under conventional interruptible rates, or persistent high prices under real-time pricing programs, exhibited fatigue. Their price responsiveness eventually diminished. Although there is a small decrease in the overall curtailment level as each event day progressed, for the most part Participants in the NYISO EDRP events were able to sustain their load reduction efforts over events that extended to eight hours. This performance lends credence to claims that PRL resources are as reliable and predictable as more conventional emergency actions, like voltage reductions, in avoiding rolling blackouts.

NYISO Payments for EDRP Load		
Zone	**Total EDRP Payments**	**% of Total**
Capital	$746,896	18%
New York	$420,895	10%
Long Island	$101,653	2%
Western NY	$2,674,234	64%
Hudson Region	$223,401	5%
Grand Total	**$4,167,079**	

EDRP Program Payments.

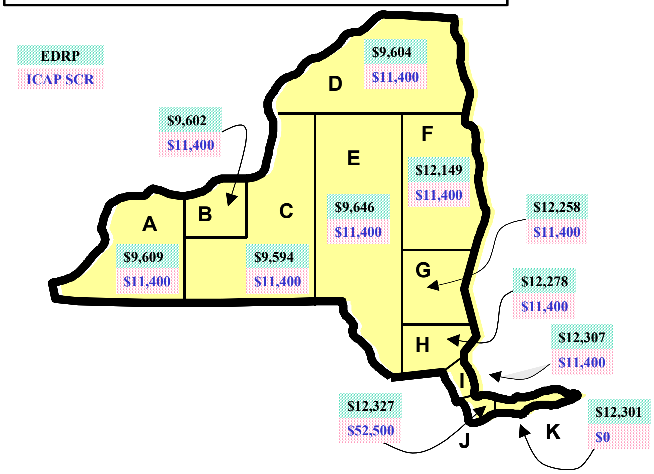
Total program payments to EDRP Participants for the four event days in August amounted to nearly $4.2 million (see the adjacent table). Almost $ 2.7 million in payments were made to Participants in

[7] One explanation for the high degree of persistence is that those PRL customers that also were subscribed to the ICAP program faced non-compliance penalties for most of these hours, since the ICAP curtailment option had been coincidently exercised by the NYISO. However, this is not a complete explanation since only 40% of PRL Participants jointly subscribed to PRL and ICAP/SCR.

western New York, a little less than $750,000 was paid to the Capital zone, and smaller amounts were paid in the other zones. [8]

The figure below displays representative EDRP and ICAP/SCR payments by zone. The EDRP values represent payments that would have been made to one megawatt of load curtailment provided in every hour of every event opportunity. The zonal variations are due to the fact that Participants in all but the Western NY zone were offered an additional six hours of curtailment opportunity, and not differences in zonal LMPS. There were only two hours in which real-time LBMPs in any zone exceeded the EDRP floor price of $500/MWH.

Estimated Summer 2001 Payments for 1 MW in EDRP and ICAP SCR



In contrast, as the figure shows, the benefits from participation in the ICAP program varied widely across the zones. The ICAP values reflect NYISO auction clearing prices for the summer of 2001 capacity period (six months).[9] While PRL payments for load in NYC are about one-third higher than for the western part of the state, ICAP/SCR payments are over four times as high. The relatively larger payments available to ICAP/SCR resources downstate, when combined with ERDP curtailment payment opportunities, provide strong incentives for downstate LSEs and CSPs to focus their marketing efforts on customers in that region in the future, and increase the proportion of EDRP resources available for dispatch in an area where they are more likely to be needed.

Effects of System Security

Load reductions during EDRP events are intended to improve system reliability. According to the NYISO Operations manual, if there is a forecasted deficiency in operating reserves, the NYISO can count dispatched EDRP load and Special Case Resources as operating

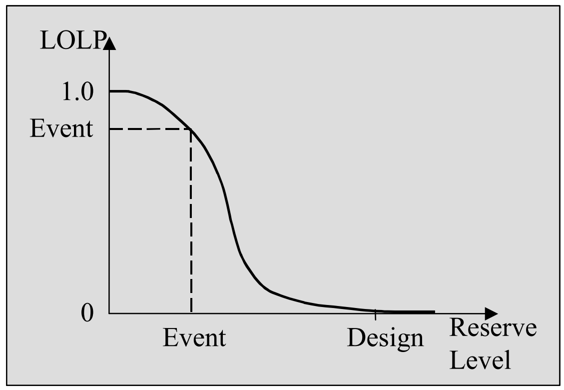
[8] The amounts reported are those paid by the NYISO to LSEs, CSPs, and direct serve customers. The latter obviously received the full benefit amount. LSE's, operating under standard offer tariff provisions, paid 90% of program benefits to Participants. CSPs did not report the terms of their benefit sharing arrangements with customers, but the standard offer 90/10 split likely influenced CSPs' deals.

[9] Customers that qualify for ICAP/SCR may sell that resources to an LSE under a bilateral arrangement, or offer it to the NYISO's ICAP auction. The seasonal strip auction price is used as a proxy for unobserved bilateral contract prices. Monthly deficiency auctions showed less regional variability, and in one case the upstate deficiency price was higher than downstate.

reserves. During the system emergencies on August 7th – 10th, EDRP and Special Case Resources accounted for roughly one third of all emergency resources called upon.

The benefits from EDRP-supplied reserves depend upon the relationship between reserves and the Loss of Load Probability (LOLP), as illustrated in the figure below. As reserves fall, at some point LOLP begins to rise at an increasing rate, increasing the likelihood of the need to shed load to maintain system security. If such load shedding is undertaken, it imposes outage costs on customers. Dispatching EDRP resources reverses that movement, thereby reducing the potential of forced service outages and generating value in terms of avoided outage costs.

Quantifying the reliability benefits of EDRP requires first determining by how much the curtailments improved LOLP. Then, the importance of LOLP must be converted into a consumer value. Ascertaining the expected level of load that would be curtailed and multiplying it by the outage costs accomplishes this. A full empirical analysis of the reliability benefits of EDRP would require reconstructing system operations at the time of each event to determine the change in LOLP. Such an undertaking was beyond the scope of this study.



To provide a framework for quantifying the reliability benefits from EDRP, system conditions for one hour during which EDRP curtailments were invoked were examined. In that hour, about 425 MW of EDRP load reduction was provided, which was estimated to have resulted in an improvement in the system reserve margin from 34% to 59%.[10] That reserve improvement likely resulted in a relatively large LOLP improvement (reduction), at least proportional to the 25% change in reserves. What value did such an improvement in reliability impart?

Industry planners and regulators use customer outage costs as a measure of the impact of service curtailment on customers, which provides a guideline to ascertaining system capacity needs. Outage costs reflect the inconvenience associated with rescheduling activities, and damages suffered as a consequence of service curtailment. Empirical estimates of outage cost vary greatly, from near zero for customers that are hardly inconvenienced, for example a residential customers that was not at home at the time, to $10,000/MWH, or more, in business

[10] The 25% improvement reflects the average conditions in an hour typical of many of those during which EDRP was called.

settings where the loss of service has catastrophic impacts. Average outage cost values from $2,500-$5,000/MWH typically have been used for system planning purposes.

To frame the extent of reliability benefits from EDRP curtailment, the relative value of EDRP curtailments in the hour chosen for examination were quantified by comparing the payments made to EDRP Participants in that hour with alternative combinations of assumptions about the change in the value of expected unserved energy associated with EDRP curtailments and alternative outage cost estimates. The table below shows the EDRP reliability benefits, during the hour examined, for four different levels of LOLP reductions, ranging from .05 to .50, and for four levels of outage cost. The average hourly system benefits outstrip the hourly program payments of about $182,000 by a very wide margin under every combination of LOLP and outage cost assumptions displayed in the table. The lowest benefit cost ratio is over seven. These estimates of the value of expected unserved energy are based on the assumption that the entire system load was at risk of being interrupted.

Hourly 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	$1,394	$2,090	$3,484	$6,968
0.10	$2,787	$4,181	$6,968	$13,936
0.25	$6,968	$10,452	$17,419	$34,839
0.50	$13,936	$20,903	$34,839	$69,678

In every case, the Value of EUE exceeds the EDRP curtailment payments

Under a more stringent view, only 5% of load was at risk for interruption. In this case, as illustrated in the table below, program payments ($182,000) would outweigh system security benefits except if both the change in LOLP and the assumed outage cost were very low. As indicated above, in the hour for which the impact of EDRP on reserves was examined, it seems reasonable to assume that the LOLP improvement was at least 0.25. Even these more conservative reliability benefits, which range from $348,000 to $1,742,000, exceed the program costs ($182,000) for that hour. Given that the generally accepted value for outage costs is in the range of $2,500-5,000/MWH, the benefit/cost ratio is between 4.8 to one to 9.5 to one.

Hourly Value of Expected Un-served Energy, *5% of Load at Risk*

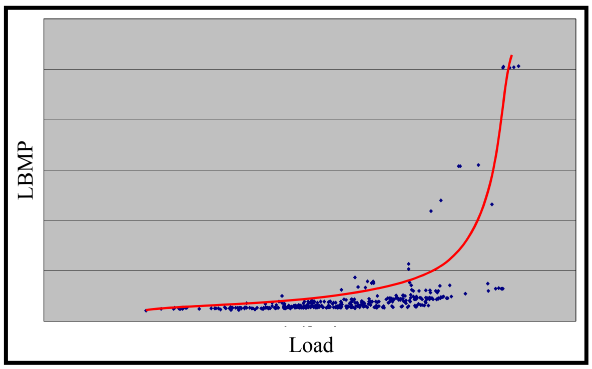
Reduction in LOLP	Outage Cost $1,000/MWH	$1,500/MWH	$2,500/MWH	$5,000/MWH
	($1,000's)			
0.05	$70	$105	$174	$348
0.10	$139	$209	$348	$697
0.25	$348	$523	$871	$1,742
0.50	$697	$1,045	$1,742	$3,484

Shaded cells indicate situatons where EDRP curtalment payments exceed event benefits

The analysis above focused on a single hour. Throughout most events, the NYISO was facing near record demands and the potential for reserve shortfall, as was the case in the neighboring electricity markets. PJMISO and ISO-NE reported demands during those periods near or above previously recorded levels. Therefore, it is likely that the evaluation of all 23 hours of EDRP curtailments would produce benefit/cost estimates consistent with those found in the hour examined

Effects on LBMP.

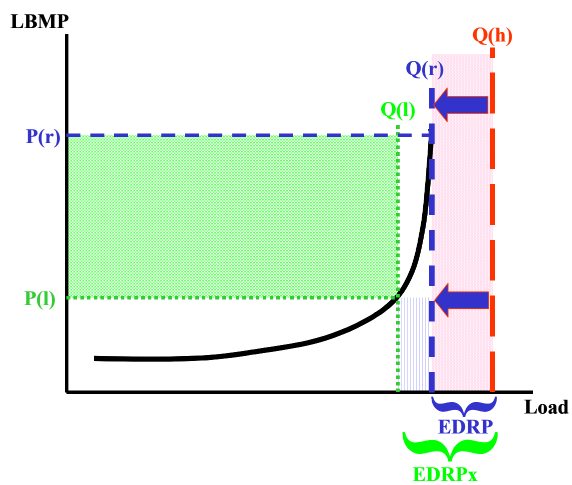
The EDRP resources are intended to resolve reserve shortfall situations. They are dispatched when no conventional generation resources are available to improve reliability. Thus their primary benefit is defined in terms of the value of that reliability improvement. However, because of the "hockey" stick shape of short-run electricity supply, as illustrated in the figure below, the deployment of EDRP resources can also result in downward pressure on market clearing prices. In that case, a joint benefit to consumers of the dispatch of EDRP resources is that downward pressure is exerted on RTM market-clearing prices. A few observations on the nature of the supply curve will put these program benefits in perspective.



The adjacent figure displays real-time LBMPs plotted against load for one of the zones constructed for this analysis for the summer months of 2001. The same basic price/quantity relationship characterizes the day-ahead prices. The stylistic curve, which brings to mind a hockey stick, indicates the form a functional relationship must take in order to capture the underlying nature of electricity supply. However, the data points themselves suggest a golf putter with a long face and a shank that extends beyond the rise of the shaft. At very high load levels, we see both very high prices, following up the shaft of the putter, and lower prices that are typical of much lower load levels, which comprise the putter's shank.

In other words, changes in market demand alone are not sufficient to characterize changes in the market-clearing price. Other factors must be taken into account to explain the price shift that occurs at some high load levels, but not at others. These include the amount of generation bid as well as transmission constraints, factors that serve to condition the supply function. They distinguish system states that result in extreme price increases at high load levels from conditions where ample generation is made available to the market to cover even high loads at relatively low prices, and therefore prices rise more slowly.

The figure below illustrates how the dispatch of EDRP resources, for reliability purposes, impacts market LBMP. Under emergency conditions, the projected load level, indicated by Q(h) in the figure, exceeds the available supply of generation resources, represented by the sharply rising curve. As a result, reserve margins are compromised. If EDRP resources just sufficient to restore market equilibrium, represented in the figure by the shift in demand from Q(h) leftward to Q(r) which intersects the supply (bid) curve, are dispatched, then market forces are again engaged, and the market-clearing price is determined from the bid curve, indicated by P(r) in the figure. The colored box in the figure between the two demand levels, demand Q(r) and demand Q(h), represents the reliability value of the EDRP resources, priced at outage cost, as discussed above.[11]



But, what if EDRPx (in the figure) represented the available EDRP resources and all were dispatched? The new market demand is shifted farther to the left, as represented by Q(l) in the figure. This new demand curve now intersects the bid curve at a lower price, indicated by P(l) in the figure. The collateral benefit arising from the use of EDRP resources is the market value of the price decrease, represented by the checkered box in the figure between the price lines P(r) and P(l). These benefits are realized by the LSEs purchasing in the real-time market at the time the EDRP resources are dispatched.

In order to quantify the impact of EDRP on LBMP, we must reconstruct the market situation. After the fact, we observe market prices that reflect the impact of the dispatched EDRP resources: they are lower than they otherwise would have been. To interpret the price impact, we need to be able to project what prices would have been, but for the dispatch of the EDRP resources. This requires estimating the supply relationship illustrated above (the golf putter) for the NYISO's real time markets for each of the modeled pricing zones and super zones. This was accomplished using NYISO RTM data for the summer months of 2001. The functional nature of these relationships can be summarized by the supply flexibility, defined as the percentage change in price for a one percent change in the load served. The steeper the supply curve, the greater is

[11] Outage costs would represented in this illustration as a very elevated price level, one which would extend the shaded box between Q(h) and Q(r) vertically to a much higher level.

the supply flexibility. The greater the supply flexibility, the greater is the impact of EDRP resources on reducing the RTM price.

The estimated average real-time supply price flexibilities are generally high, but they vary substantially across the modeled zones, as illustrated in the table below. The corresponding day-ahead supply flexibilities, which are used in the evaluation of the DADRP program below, are provided for comparison. The highest EDRP price impact is in those zones that are also most likely to require the dispatch of available EDRP resources. The real-time supply flexibilities are highest in New York City (NYC) and on Long Island (LI), 14.5 and 10.4, respectively. A one percent load reduction in NYC would result in a 14.5% reduction in LBMP, while a similar load curtailment in Long Island (LI) would reduce LBMP by 10.4%.

Supply Flexibilities for NYISO Electricity Markets		
Zone	Real-Time	Day-Ahead
NYC	14.5	9.4
LI	10.4	5.1
Capital	8.4	11.8
Hudson	8.6	5.1
Western	6.4	9.4
Estimates for summer 2001		

In the day-ahead markets, the supply flexibilities are high again in NYC and Western NY (9.4), and higher still in the Capital (11.8) zone. This suggests that the DADRP program, which primarily affects prices in the day-ahead market, is particularly well suited for those zones. The values provided in the table above are average flexibilities corresponding to the high load/high price hours. As suggested above, the model specification allows the flexibility to differ by hour to reflect contemporary system conditions. These differences by zone and by hour, combined with the size of the EDRP load reductions in each hour, were used to quantify the collateral price effects.[12]

Collateral Benefits.

The impact of EDRP curtailments on market prices and the corresponding collateral impacts are presented in the table to the right. LBMPs in the event hours are estimated to have been reduced by approximately 28.8% in the Capital and by 21.5% higher in the Western New York zone. The relatively high real-time supply price flexibility estimated for the New York City and the Hudson

Impact of EDRP on Real-Time Zonal Prices			
	Average Hourly Event Value		
Zone	% Reduction in RT LBMP due to EDRP	Collateral Benefits	Total Collateral Benefits
Capital	28.8%	$132,009	$3,036,211
New York	4.1%	$106,044	$2,439,005
Long Island	0.6%	$9,274	$213,294
Western NY	21.5%	$353,306	$6,359,512
Hudson Region	3.8%	$39,416	$906,559
Grand Total			$12,954,581

[12] In some EDRP event hours, other emergency actions were undertaken which contributed to improving reserves. The use of event point supply flexibilities, as opposed to the higher overall average supply flexibilities, to calculate the price impacts of EDRP load curtailment, results in an underestimate to the impact measured over the entire set of reserves deployed.

Region produced EDRP load reduction of 4.1% and 3.8%, respectively, despite the fact that EDRP resources amounted to under one percent of the zonal load served.

The collateral benefits arising from load curtailments represent transfers to buyers from sellers. Because of the steep slope of the electricity supply curve, as measured by the large flexibility values, these benefits would be substantial if all load were purchased in the RTM if the price reduction would effect all load transactions. Under this whole-market perspective, during the events of August 2001, these collateral benefits were estimated to be almost $13 million.[13]

This valuation underlies the very large benefits attributed to the value of PRL in California electricity markets last year when reserve shortfalls were large, since at the time most retail load was purchased at the RTM price. Since only about 5% of LSE's load obligations are transacted in the NYISO RTM, the direct collateral benefits are substantially smaller, about $650,000. However, all buyers benefit from the price suppression impacts of EDRP. It is the fear of the potentially high RTM price volatility that motivates LSE's to hedge their position bilaterally or through day-ahead market transactions. Because EDRP reduces RTM price volatility, all buyers benefit from the larger market impacts.

Effects on Average LBMP and its Variability.

By reducing the number of extreme prices in the RTM, one might expect EDRP load to abate both average LBMPs and the variability in LBMPs, thus adding importantly to the liquidity of the market. This indeed appears to be the case.

Compared with the average LBMP, EDRP curtailments during the four events in August are estimated to have decreased RTM LBMP by over $4/MWH in the Capital zone, and by nearly $2/MWH in western New York (see the adjacent table).[14] Although these effects are relatively modest, if these programs persist in the long run and as a result market Participants come to expect that real-time LBMPs are likely to be lower and less variable, eventually this influence will be reflected in downward pressure on prices

EDRP Effects on Real-Time Market LBMPs

Zone	Difference in Mean RT LBMP	Estimated Long-Term Reduction in Cost of Hedging Load
Capital	$4.05	$851,778
NYC	$0.66	$831,658
Long Island	$0.12	$61,709
Western NY	$1.91	$1,880,389
Hudson Region	$0.60	$242,989
Grand Total		$3,868,525

[13] While is tempting to compare the collateral benefits with the payments to Participants in order to construct a benefit/cost test, such a comparison is not appropriate. The collateral benefits reflect transfers from generators to LSEs and possibly eventually to retail customers, to overall improvements in welfare. Improved reliability does improve welfare, and does lower price volatility.

[14] Price effects reflect the estimated impact over hours from 6:00 a.m. to 10:00 p.m. during weekdays in August. These benefits were derived by comparing monthly zonal prices for LBMPs as posted by the NYISO with the LBMPs reconstructed using the zonal supply flexibility relationships.

at which LSEs pay to hedge their load obligations, either through physical bilateral supply contracts or financial hedges.

The long-term impacts on hedged prices appear to be substantial. In total, the August hedging cost reductions were estimated to be about $ 3.9 million, the largest portion of which accrues to the Capital zone (22%) and to western New York (48%).[15] These benefits reflect the availability of PRL load to provide market liquidity, the consequences of which are lower market prices. If more customers enroll in EDRP, or Participants' load responses increase, or both, then so do these benefits. Moreover, this risk mitigation effect might well persist throughout all the summer months, which could more than double the level of benefits.

These potential cost savings are probably lower bounds on the actual savings because they do not take into account the pressure on hedging prices due to the fact that EDRP curtailments reduced RTM price volatility as well. To estimate the effect of lower variability on the price of hedges, it would be 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). Ideally, one would want to apply a financial model to calculate the changes in hedge prices to account for the effects of changes in both the mean and the variance in LBMP to provide a more complete indication of the value of PRL loads. This in-depth financial analysis was beyond the scope of this study, but represents a logical next-step in evaluating PRL programs.

An Examination of the Day-Ahead Demand Response Program

The primary difference between the impact of EDRP and DADRP relates to the mechanisms by which the load curtailments are integrated into NYISO operations. DADRP load curtailment bids are *scheduled* into the day-ahead market, based on the Participants' curtailment bid prices and specifications relative to supply bids of generators. Conversely, EDRP load curtailments are *dispatched* by the system's operators, based on their reckoning of the need for reserves.[16] The effects on the markets can be traced in similar fashion, except that the effect of EDRP is obviously in the RTM, while the primary effect of DADRP is in the DAM, at least initially. As enrollment in DADRP expands over time, increased activity in DADRP may ultimately reduce the frequency of system emergencies under which EDRP load is needed, thereby imposing discipline on RTM prices and reducing reliance on EDRP resources.

[15] Hedging benefits were derived assuming that 40% of all load requirements of LSEs were purchased in the DAM, which corresponds to the current average level of such purchases across the state.
[16] Participants bid DADRP resources identical to the way generators bid conventional resources. Hourly DADRP bids can be partitioned into sequential blocks of successively higher strike (curtailment) prices, and bidders may specify minimum runs times and curtailment cost guarantees that in effect allow Participants to bid continuous strips for curtailment, on an all or nothing basis.

DADRP Scheduled Bids.

Activity in DADRP this past summer was modest relative to that of EDRP. There were 16 Participants in DADRP statewide, but there were no Participants in New York City or Long Island. Furthermore, not all of the DADRP Participants actually submitted bids. Only those in the Capital zone and in the Western "super" zone offered bids and had them scheduled. As a result, the analysis of the impacts of DADRP on NYISO market prices is restricted to those zones.

DADRP Load Scheduled.

A total of 2,694 MWH of DADRP curtailment bids were accepted, over 46% in the Capital zone and 54% s in NYISO's Western zone (see the table below).[17] In the Capital zone, 45% of the MWs were for bids accepted in July, while 55% were for bids accepted August. All of the bids accepted for customers in western New York were in the month of August. On an hourly basis, the average curtailment bids accepted was 5 MW in western New York; and individual bids they ranged in size from 1 MW to 20 MW. In the Capital zone, the average hourly load accepted was smaller, averaging 3 MW per participant, and exhibited the same range of curtailment bids.

Impact of DADRP on DAM Zonal Loads			
Zone	Hourly Average Event Value		Total DADRP Load (MWH)
	DADRP Load (MWH)	% Change in DAM Load due to DADRP	
Capital	3	0.2%	1,231
Western NY *	5	0.3%	1,463
Grand Total			**2,694**
* Central zone was only zone in Western NY with scheduled DADRP load			

In the Capital zone, DADRP bids were accepted in 370 separate hours, while in the western zone, DADRP bids were accepted in 279 separate hours. Some of the accepted bids were for the early morning or late evening hours, and as would be expected, given the relative low prices typical of these periods, they were bid in at relatively low prices.

Some DADRP bids were accepted (scheduled) on the four EDRP-event days in August. For the Capital zone, about 26% of the total DADRP load bids scheduled were on the EDRP event days, and about 24% in the Western zone. However, the coincidence of scheduled bids and EDRP event hours was low. Less than 25% of the load scheduled during what turned out to be event days was during actual EDRP event hours. This apparent paradox might be due to joint EDRP/DADRP participation. If customers believed that there was a high likelihood of an EDRP event during the peak hours of the next day, then they would find it compelling to bid the $500

[17] DADRP bids are submitted of behalf of individual customers and aggregations of customers that have agreed to a common bid structure. In the latter case, the number of actual firms bidding is not disclosed as part of the bid. The bidding activity reported therefore involves more firms than the number of bids indicates.

EDRP floor prices for DADRP curtailments during those hours, which maximizes their payments given their expectations.

DADRP Program Payments.

In contrast to EDRP, Participants in DADRP are paid their bid amount (which can include start-up costs) or LBMP in the DAM, whichever is higher. Therefore, payments vary considerably between the two zones, reflecting local market conditions.

NYISO Payments for DADRP Load		
Zone	Total DADRP Payments	% of Total
Capital	$134,232	62%
Western NY	$83,255	38%
Grand Total	$217,487	

Total DADRP payments were $217,487, or about $81/MW of delivered curtailment.[18] While 46% of the scheduled load was in the Capital zone, those curtailment bids, which averaged $109/MWH, accounted for 62% of the total payments.[19] Payments for scheduled curtailments in western New York were lower, averaging $57/MW. This difference is due to the higher average price in the Capital zone on days when bids were accepted, but also reflects the bidding strategy of those Participants.

Effects of DADRP on LBMP in the DAM.

The goal of DADRP is to increase day-ahead market access to retail customers with the expectation that scheduled curtailments will exert downward pressure on market prices and their volatility, which ultimately will be reflected in lower costs of electricity to retail customers, even those that select service plans with hedged prices.

Impact of DADRP on DAM Zonal LBMPs			
Zone	Hourly Average Event Value		Total Collateral Benefits
	% Reduction in DAM LBMP due to DADRP	Collateral Benefits	
Capital	0.9%	$2,781	$1,029,049
Western NY *	0.3%	$1,641	$457,851
Grand Total			$1,486,900
* Central zone was only zone in Western NY with scheduled DADRP load			

A relatively small number of customers actively bid in DADRP; the maximum scheduled peak period load was 25 MW. DADRP scheduled loads accounted for, on average, less than one-half of one percent of the total system load accounted for in the DAM. Moreover, estimated supply flexibilities in the Western and Capital zones were estimated to be

[18] DADRP customers are allowed to bid start-up (more appropriately outage) costs, along with the energy price they require to curtail. Their bids are evaluated on an equal footing with generators' bids in the dynamic programming part of SCUC. When both start-up costs and energy costs are considered jointly, they clearly were a cheaper source of energy than competing generators for these relatively small amounts of load.

[19] At the time this analysis was completed, the settlement data for DADRP had not been fully processed by NYISO. Therefore, the program costs provided assume that DADRP curtailment payments were equal to LBMPs in the DAM, and for this reason, they exclude any start up costs included in customers' bids that were accepted. Actual DADRP payments will likely be higher by 20-30%.

half of the corresponding DAM levels. As a result, one would expect that the effects of accepted bids on LBMP in the DAM would be smaller than for EDRP.

This was the case. Scheduled DADRP curtailments are estimated to have reduced market-clearing LBMP in the Capital zone by just less than one percent and in the Western zone by about a third of one percent (see the table above), compared to EDRP price impacts of up to 25%. The greater impact in the Capital zone arises in part from the fact that during the hours in which bids were accepted, the price flexibilities of supply were on average somewhat larger in the Capital zone than in the Western zone. In other words, those bids were somewhat better aligned with market conditions and therefore produced higher curtailment prices.

Collateral Benefits.

As is the case of EDRP, the collateral benefits of DADRP on the DAM are transfers to buyers from sellers. These benefits are more germane to DADRP performance than for EDRP because the primary goal of DADRP is to expose market transactions to customers' willingness to pay for electricity, resulting in downward pressure on the market prices. As a result of DADRP scheduled curtailments last summer, total collateral benefits are estimated to be almost $1.5 million, two-thirds of which are attributable to the Capital zone.

Effects on Average LBMP and its Variability.

By affecting the number of extreme prices, one might also expect DADRP load curtailment bids to reduce both average LBMPs and the variability in LBMPs in the DAM. This is the case, although the effects are not as dramatic as those due to EDRP load curtailments. The average LBMP in the DAM for the hours from 6:00 a.m. to 10:00 p.m. during August was estimated to be $1.42/MWH lower in the Capital zone and by $0.51/MWH lower in the Western zone, which are 30% and 25%, respectively, of the corresponding EDRP impact on zonal RTM prices.

These effects are extremely modest. But, if these programs expand in the long run, and market Participants come to expect that LBMPs in the DAM are likely to be lower and less variable, these impacts will eventually be reflected in the prices at which customers can hedge load. DADRP curtailment bids are estimated to have resulted in $675,000 of benefits associated with lower DAM LBMPs, and they would be substantially more if price reductions were expected to persist throughout the summer, and as a result hedging prices were lowered in all months.

Finally, and perhaps most important, if active participation in the day-ahead wholesale market for electricity were expanded significantly beyond the small number of first-year Participants, they could contribute importantly to the discipline of the day-ahead market -- both in terms of lowering the average price, as well as abating price volatility. More stable prices will reduce standard offer retail prices, and encourage new entrants to become involved in New York's retail markets.

What was learned about Customer Behavior?

The impact of PRL programs on system reliability and the size of collateral market impacts depend both on the number of customers participating in the programs and the load response offered by each Participant. A complete evaluation of these programs therefore requires understanding how load responsive customers can be, and what influences their decision to subscribe to PRL programs in the first place.

Two initiatives were undertaken to characterize price responsiveness to the PRL programs and how customers value and perceive these programs and their features. Participants' relative price responsiveness was quantified by calculating implicit price elasticities for individual customers. A price elasticity provides a convenient means for comparing customers' ability and willingness to shift usage in response to price changes. Customers that exhibit higher elasticities will realize greater benefits from participation, and their load curtailment actions will generate greater reliability and collateral benefits.

A survey was administered to EDRP and DADRP Participants and to other customers to measure customer satisfaction with the programs, and to provide data for the development of behavioral models to identify and quantify factors that explain why customers chose to participate, and how customers would react to alternative program designs. The results of these analyses provide insight into how program participation and response can be improved.

Participant Implicit Price Responsiveness.

Participants' usage during EDRP event hours was on the average about 61% of what it would have been otherwise, as measured by the Customer Base Load (CBL), the basis against which payments are made.[20] To develop a better understanding of character of customer load response, individual Participants' load curtailment performance was analyzed.[21]

EDRP load curtailments can be described in terms of the price elasticity of demand; e.g., the percentage change in load (the curtailment) with respect to the percentage change in price. The price change is the difference between the background tariffs applicable to Participants' electricity consumption (the average of which was approximately $95/MWH) and the guaranteed

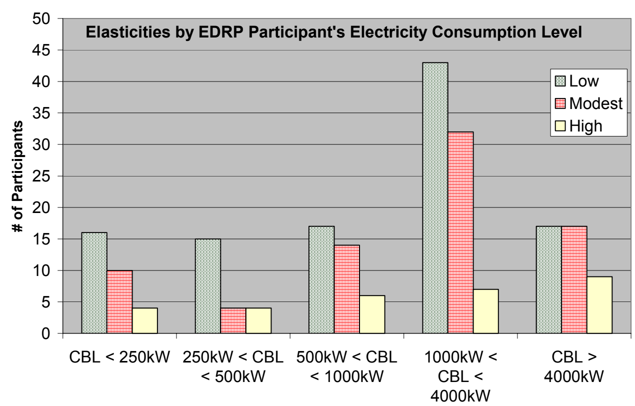
[20] The CBL is the customer's average usage, during event hours, on the five highest of the ten previous days, excluding day when event were called and excepting weekend days, the CBL for which is the average of the previous three like weekend days.

[21] Because bidding in the DADRP was light, and the full season of load data needed to estimate demand functions were not available; response elasticities analyses were restricted to EDRP Participants. Moreover, Participants operating generators were excluded.

EDRP payment level ($500/MWH).[22] Hourly price elasticities were calculated by solving for the elasticity implied by the quantity (load) change resulting from this price spread. The values reported should be viewed as *implicit* price elasticities, since they do not directly take into account other factors that influence load changes. The hourly load and detailed customer characteristic data needed to estimate demand relationships, which would yield more robust estimates of the elasticity, were not available.

The average implicit price elasticity for EDRP Participants was estimated to be about -0.9, which implies that EDRP Participants would reduce their usage during declared events by about 31 MWs on average. The estimated elasticity values compare favorably with demand response from previous studies of TOU and real time pricing programs, which reported portfolio response elasticities in the -.10 to -.25 range. The implicit demand elasticities calculated for EDRP Participants vary by customer and zone, ranging as high as - 0.47 (e.g., a 4.7% response for every 10% that the guaranteed payment level exceeded the background tariff).[23] Elasticity estimates for a few customers were positive in sign: their usage increased during the events.

In general, the larger customers with loads of one megawatt or greater exhibited the highest price responsiveness. But, there were also a number of smaller customers that demonstrated above modest to high responsiveness, as the adjacent figure shows. Larger customers are more attractive targets for marketing PRL program because of the high transaction costs associated with recruitment, they provide more response per dollar spent. As the elasticity estimates suggest, many smaller customers may be proportionally more responsive, and therefore make good candidates for participation. Through education, training, and perhaps some financial assistance to purchase necessary meters and other equipment, more of these types of customers would find



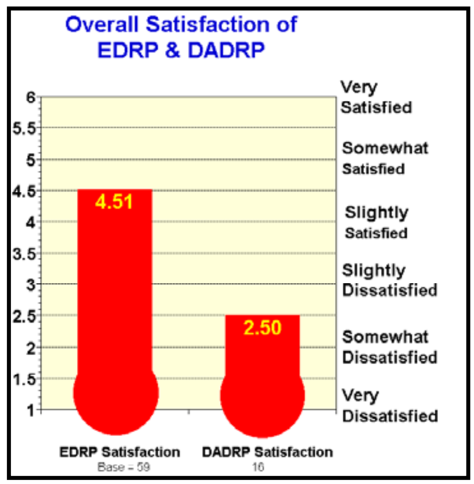
[22] Tariff rates faced by Participants were derived from the applicable standard offers rates offered by the franchise LSE with POLR responsibility. These rates varied by more than 25% across the zones. Furthermore, some EDRP Participants take commodity service from a competitive LSE, which introduces further, but observed, background rate variations.
[23] The reported EDRP elasticities are arc approximations of the underlying nature of the demand relationship, and therefore should be considered as providing a good approximation only at prices close to those actually observed.

participation in these PRL programs of value, and be likely to actively pursue opportunities to do so.

Customer Satisfaction

The best way to find out why customers participated in these PRL programs, or if they will in the future, is to ask them. To learn more about how customers perceive the PRL value proposition, a survey was conducted upon Participants and informed non-Participants, the latter defined as customers that were specifically targeted to receive information about the programs because they were seen as potential candidates, but chose not to subscribe. About one third of the population of Participants responded to the survey administered in the fall of 201. While the response rate was lower for informed non-Participants, it does not appear that there was a systematic bias, with the exception that Participants that used backup generators were underrepresented at the firm level.[24]

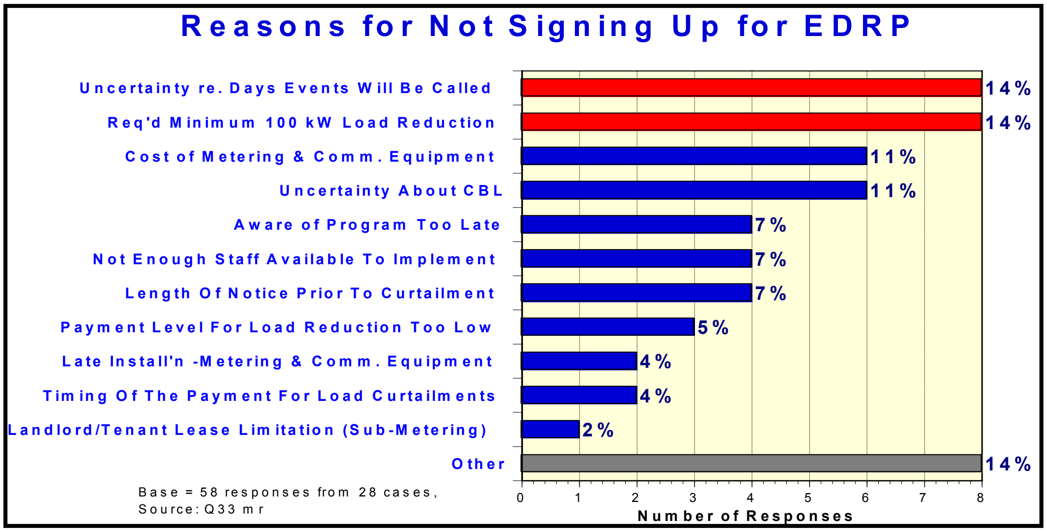
The results of this survey indicate that while EDRP Participants were quite satisfied with the program, DADRP Participants were considerably less satisfied (see the adjacent graphic). It is not surprising that those who were most satisfied with the current programs indicated that they would most likely subscribe to programs offered next year. The high satisfaction with EDRP derives mainly from high reported satisfaction with the $500/MWH floor price for curtailments. Dissatisfaction with DADRP is associated with some Participants' low program benefit expectations combined with complaints about the long time that expired between when they curtailed usage and when they were paid.



Customers that reported that they had participated previously in RTP or TOU programs were more likely to have participated in EDRP or DADRP. One advantage to the EDRP in this respect is that curtailments are voluntary, which reduces Participants' risk and makes the initial subscription easier to accept.

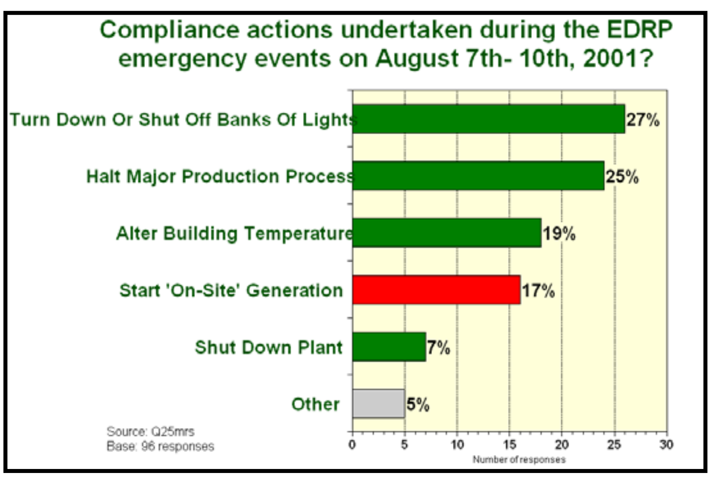
[24] The two respondents (out of over 20 firms) to the survey that dispatched on-site generators when EDRP events were declared represented over 50 generation units, which comprised over half of all enrolled generators.

Non-Participants offered a variety of reasons for not signing up for EDRP, as illustrated below. The most common being uncertainty about when they would be called upon to curtail and the requirement that each customer, or customer aggregation, be able to curtail at least 100 kW of load. Metering costs and CBL uncertainty were also reported relatively frequently as reasons for not participating.

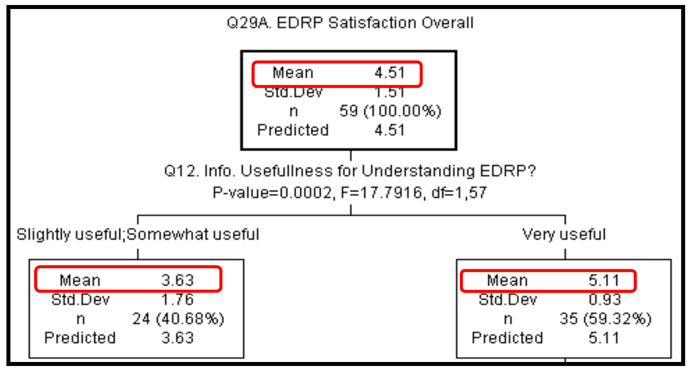


By far the most common (21% of respondents) reason given for not participating in DADRP was the penalty imposed when scheduled curtailment obligations are not met, although the lack of sufficient curtailable load and insufficient staff to implement curtailments were also reported as barriers by more than 10% of respondents.

Survey respondents reported being generally aware of how they use electricity, with the noon to 4:00 p.m. period reported as being the time of peak usage by a majority of respondents. PRL Participants reported employing a variety of strategies to respond to EDRP curtailments, as illustrated in the adjacent figure. Turning down lighting and air conditioning was mentioned quite frequently. A quarter reported shutting down a production process, generally a drastic step and one that indicates a commitment to earning curtailment payments.



Respondents' satisfaction with the information they received, from NYSERDA, LSEs, and CSPs, describing the EDRP program had a large impact on their overall satisfaction with the program. Overall, satisfaction with the EDRP program opportunity was 4.51, where a ranking of 6.0 indicates *highly satisfied*. As illustrated in the figure below, when responses are sorted according to how respondents rated the usefulness of the program description information they were provided with, the overall rating was significantly higher for those that found that information very useful.



These results suggest that when properly presented, the EDRP program and its provisions are comprehensible to customers and that they find them attractive. Given the importance of how the program opportunity and value proposition are portrayed in the participation decision, and the need to customize these materials to different market segments, the returns to collaboratively developed educational programs would be high.

Revealed Preferences: The Decision to Participate in a PRL Program.

The survey asked Participants to provide data that characterize their business operations and how they use electricity. Combined with responses to survey questions concerning preferences for EDRP features, these data provide the foundation for building a behavioral model that characterizes the factors that distinguish EDRP Participants from customers that evaluated the opportunity, but chose not to participate.

Identifying those factors that led firms to participate in the current EDRP involves an analysis of the *revealed* preferences of customers' decisions whether or not to participate in EDRP. Analysis of revealed preferences is the mainstay of the economic analysis of consumer and firm behavior, and it enjoys widespread use in many fields because it associates observable customer characteristics with specific decision outcomes. In this case, the firm characteristics and the respondents' answers to survey attitudinal questions constitute the stock of revealed information from which the characteristics of a customer likely to participate are constructed and evaluated. The decision to participate (a binary variable) is specified as a function of the customer's firm characteristics and other indicators of preference that is estimated from survey data using a binary logit choice model.

The coefficients of the choice model estimated for this purpose can be interpreted as an "odds ratios"--the *ceteris paribus* odds of program participation for a firm with those particular characteristics relative to firms not having them, or having them to a lesser degree. The higher the odds ratio, the greater the likelihood that the customer would participate. Customer characteristics that contribute significantly to the odds ratio constitute markers that can be used to search out the best candidates for program participation.

The adjacent table displays the results of the revealed preference analysis. Odds ratios are reported for those factors that were found to contribute to explaining EDRP participation. One important result is that firms with peak electricity usage during the afternoon hours of noon to 4:00 p.m. are more than 3.6 times as likely to participate in EDRP as are firms that peak at other times. Customers apparently recognize the high probability that EDRP events will be declared in the early afternoon hours, and that to benefit from participation, they have to have load to curtail during that time.

Customer's w/ Firm Characteristics
Odds of Participation in PRL Programs

Firm Characteristic	Odds Ratio
Understand Notice	2.4
Peak-12-4pm	3.6
Production Shifts	2.0
In Other LSE Program	3.4
EDRP Info Very Useful	0.3
% of Model's Correct Predictions	83
% of Model's Incorrect Predictions	16

$$\text{Odds Ratio} = \frac{\text{Prob (Participation)}}{[1 - \text{Prob (Participation)}]}$$

Firms with prior experience in an LSE's load management program are also over 3 times more likely to participate than those with no prior experience. That result is intuitive. Since these customers are familiar with how PRL programs work, and they are more likely to have invested in behaviors and technologies that enable them to be price responsive. Firms with an additional production shift were found to be twice as likely to participate *ceteris paribus* than those firms with a single production shift, perhaps reflecting their greater scheduling flexibility.

These variables, the number of production shifts, nature of electricity use, and prior experience, provide indicators that can be used to characterize customer for which EDRP is well suited. The last result presents a conundrum given that most customers were not previously involved in a program like EDRP and DADRP; customers once having participated in PRL programs, are more likely to participate in them. How does the cycle begin? Fortunately, the choice model results also suggest a solution: knowledge is a substitute for experience. Educating customers on how to reduce load, for which Understand Notice is a proxy with an odds ratio of 2.4, while not a perfect substitute for prior experience, will increase participation.

Finally, if firms found the information they received about EDRP very useful, their odds of participation are 3 in 10. On the surface, this result may sound counterintuitive, but there is a good explanation. This result suggests that if the initial information about load management programs is effective, then customers can make informed, correct decisions, even if the decision is to not sign up. Thus, if efforts are made to generally and effectively educate customers about these types of programs, firms will sort themselves into those who find no value in the program and those who see some value and should be recruited seriously, thereby reducing marketing costs. A central theme to the results of the customer preference and attitude research is the importance of conveying the value proposition to customers in an understandable and compelling manner.

Valuing Program Features.

The particular design of PRL programs and program features will affect customers' willingness to participate. Unfortunately, since the NYISO's programs are in their first year of operation, there has been no opportunity for customers to "reveal" their preferences for alternative program features. They had only EDRP and DADRP to chose from.

To shed some light on how customers would value changes in these several features of PRL programs, a conjoint survey was administered to solicit customers' *stated* preferences for different program characteristics.[25] These are stated preferences because customers are asked to make choices between contingent and hypothetical options regarding new PRL products or new combinations of program features. A multinomial logit choice model was estimated using the conjoint survey responses to assign relative utility values to program features, thereby facilitate determining how changes in features affect customers' overall preferences for participation.

Two programs were created to illustrate how this model can be used to refine and improve PRL program design. The adjacent table describes the features of these two reference PRL program designs. The *Base Program* is comprised of attributes that closely approximate those of EDRP. The *Hypothetical Program* was constructed to resemble DADRP attributes. The choice model was used to determine the odds of participation in the base program relative to no PRL program at all. Then, odds ratios were derived for participation in the hypothetical program relative to the base program and relative to no program at all.

Comparison of Evaluated PRL Programs

Program Features	Base Program	Hypothetical Program
Payment	$500/MW	$500/MW
Penalty	0.0	0.1
Start Time	1300 HRS	1400 HRS
Notice	2 HRS	Noon Day-Ahead
Duration	4 HRS	4 HRS

[25] The conjoint survey was administered along with the attitudinal and satisfaction survey.

The analysis was conducted separately for EDRP Participants and survey respondents not currently in EDRP. They were asked to make several selections from alternative product bundles that were comprised of different levels of curtailment payment (from \$100 to \$750/MWH), noncompliance penalty (from none to two times the payment), notice (from 15 minutes to a day ahead), duration (from 1 to 8 hours) and event start time (as early as 11:0 a.m. to as late as 2:00 p.m.). The choice model provides a means for integrating the results into a cohesive representation of respondent preferences over the range of examined product feature values. Before reviewing these results, it is instructive to summarize the overall valuation respondents assigned to the program features.

There are several striking relationships in comparing the value, often referred to as utility, of features across the two sub-groups:

- For EDRP Participants, the marginal utility for lower and higher payment levels is very high, while for non-Participants the utility for the payment level is relatively flat.
- The disutility of the penalty is more pronounced for EDRP Participants.
- Both sub-groups prefer later event start times, but the preference is more pronounced for the non-Participant groups.
- There is a general preference for a longer notice period by both groups.
- There is a preference for longer event durations, particularly for current EDRP Participants.

The analysis of the odds ratios for EDRP Participants is presented in the table below. The cell values are the odds ratios for the corresponding row and column program comparison. For example, if Participants were faced with the decision were between *No Program* (stay with their existing service provisions) and the *Base Program* (EDRP), the model puts the odds at 3.46 to 1 that they would sign up for EDRP, which confirms the model's conformity with actual experience.

Odds Ratios of Participation for EDRP Participants

	Base Program	Hypothetical Program
Base Program	-	0.88
No Program	3.46	3.05

Despite their preference for EDRP features, there is close to even odds (0.88 from the adjacent table) that EDRP Participants would subscribe to the *Hypothetical Program*, which mirrors the current Day-Ahead program, if the alternative was the *Base Program*. Moreover, they preferred the *Hypothetical Program* to *No Program*, by over 3 to one odds.

These are important findings. If an improved capacity situation erodes the expected benefits of EDRP, in other words the choice is between *No Program* and the *Hypothetical Program*

(DADRP), Participants may be persuaded to switch to DADRP because it offers ongoing, albeit lower value to them.

The table below presents the corresponding results of modeling stated program preferences using non-Participants responses to the conjoint survey. As one might well imagine, the utility of the *No Program* option for non-EDRP Participants is higher. Thus the odds of participation in the *Base Program* (EDRP) are less than even (0.68). In order to participate, these customers would need a product package with utility, one that provided greater value in the form of a higher payment for curtailments, more notice, or a later start time in order to increase the odds of participation.

Odds Ratios of Participation for EDRP Non-Participants		
	Base Program	Hypothetical Program
Base Program	-	1.53
No Program	0.68	1.03

However, as the table shows, however, if the choice were between the *Hypothetical Program* and the *Base Program*, the odds are greater than even (1.53) that non-Participants would chose the hypothetical program. The *Hypothetical Program* resembles DADRP participation with a strike price for curtailment of $500/MWH. This suggests that DADRP curtailment bidding is a viable alternative to EDRP because its longer notice overcomes the disutility associated with a shorter notice.

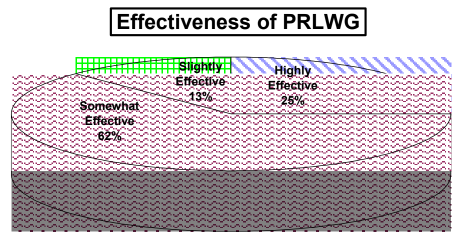
On balance, customers' *stated* choices are largely consistent with their choice to participate or not participate in EDRP this past summer. They also indicate that adjusting certain program features in the future would increase participation, and that customers might be more inclined to participate in DADRP if the expected benefits for EDRP decline. This underscores the fact that in program design, there are substantial tradeoffs between those features of value to the market and those of value to customers. The key is to find a balance that produces benefits for both Participants and other stakeholders.

PRL Program Process Improvement

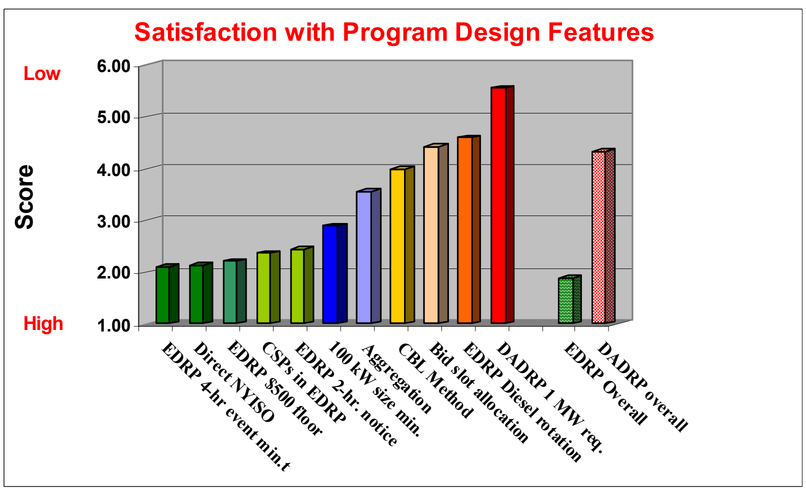
The Process Improvement survey instrument asked LSEs and CSPs to indicate their satisfaction with how the NYISO performed its role in organizing and coordinating the PRL program design, and administering the programs implemented. Respondents were also asked to voice their satisfaction with the Department of Public Service's regulatory oversight process that effected LSEs directly and CSPs indirectly. Surveys were completed by six LSEs and three CSPs.

The LSEs reported that they had offered load management programs to their customers in the past, mostly to larger commercial and industrial customers. All the LSEs reported that they had intended to design and implement their own PRL programs in 2001, but four of them indicated that the program they had planned to offer was quite different from that which was eventually implemented. At several other junctures, LSEs indicated that they preferred to design and operate their own programs outside of the NYISO's suzerainty. [26]

Respondents were generally satisfied with how the NYISO performed its program design and implementation functions. The Price Responsive Load Working Group (PRLWG), which was set up by the NYISO to facilitate the design of these programs, was judged to be generally effective. However, some felt that there was a bias toward wholesale interests that compromised retail interests and led to programs that were overly complicated and not attractive to retail customers.



Respondents to the performance improvement survey indicated that while they were very satisfied with some of the specific programs' features, others were less well received. They approved of provisions that reduced EDRP participant's uncertainty regarding what they would be paid when they curtailed, reporting high satisfaction with the payment level floor ($500/MWH) and the minimum event duration (4-hour). They also reported being more than satisfied with the 2-hour notice provision and were generally satisfied with customers subscribing directly to the NYISO, instead of through an LSE or CSP.



LSE's expressed dissatisfaction with how bids slots were allocated and the one MW bid minimum and increment for DADRP.[27] Because DADRP curtailment bids are modeled in the

[26] NYISO market prices had exhibited periods of considerable volatility prior to the summer of 2001, causing the LSEs that were not hedged to consider implementing load management programs that would provide them some leverage in purchasing their needs in the day-ahead and real time markets. Some indicated that they were well along with their plans for such programs that they believe would have provided them with greater value than those that were promulgated by the NYISO and became the standard offer.

[27] Only LSEs were allowed to sponsor customer participation in DADRP during the summer of 2001. CSPs will be able to market both EDRP and DADRP beginning in 2002.

NYISO scheduling algorithms as generators, bids were restricted to whole one-megawatt increments. Furthermore, because of limits on the number of bid slots the model can accommodate, slots were allocated across the pricing zones and made available on a first come basis. LSE's expressed dissatisfaction with that process, and its results, despite the fact that all customers that desired and eligible to bid were apparently accommodated last summer. LSE's most likely are anticipating the effect of these provisions when requests for program participation expand significantly, which may be as soon as 2002 when CSPs are eligible to market DADRP.

Both LSEs and CSPs expressed dissatisfaction with the provisions for a round-robin diesel generation dispatch. Due to environmental restrictions, the NYISO agreed to limit the dispatch of diesel generators under EDRP to 150 MW at any time.[28] A round-robin provision was adopted to provide customers deploying on-site diesel backup generators a fair opportunity to participate if the total of such resources available exceeded 150 MW. The provision was met with dissatisfaction, despite that fact that it did not come into play, as diesel generators comprised less than 100 MW of the total available EDRP resources. Again, these protests may be more anticipatory than experiential in nature.

Overall, LSEs and CSPs reported being quite satisfied with the features of EDRP, but quite dissatisfied with those of DADRP. High LSE/CSP satisfaction with EDRP features matches that of customers, as derived from the customer survey response, and supports maintaining the same program design for the second year of the pilot. The low score for DADRP, which also correspond generally to customers' perspective, stems partly from dissatisfaction with program administration. Some respondents indicated that the late approval and implementation of the program also hindered their ability to prepare and deliver adequate marketing information, which kept participation low. However, others expressed their conviction that customers simply are not willing to undertake the risks inherent in DADRP participation. This perspective is at odds with the findings of the choice modeling.

Some LSEs reported being not very satisfied with the Department of Public Service's requirement that they implement standard offer programs derived directly from the PRL programs the NYISO made available. Two-thirds of LSE's are in favor of having the freedom to design and implement PRL programs as they see fit, and all but one indicated that they should be allowed cost recovery for the programs they offered, although one LSE that was in favor of design freedom preferred an incentive-based system. The CSPs responding favored enforced uniformity in LSE programs, and opposed cost recovery.

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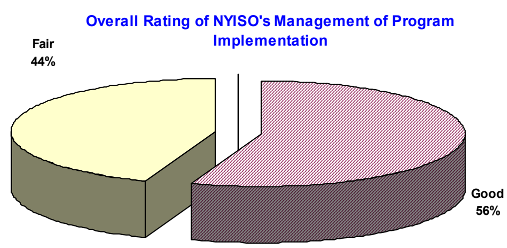
[28] On-site diesel generators are allowed to participate in EDRP, but not in DADRP.

Respondents reported being generally satisfied with the program manuals prepared by the NYISO, but more so with that designed for the EDRP. Satisfaction with the training provided by the NYISO rated slightly lower, with specific references made for the need for better-organized DADRP training provided on an ongoing bias. Given the importance of educating customers in order to increase participation and build up price responsiveness, as established in the evaluation of program performance and as evidence from the analysis of the customer survey, an investment in training programs to assist LSEs and CSPs in marketing PRL programs would yield high returns in terms of the overall program success.

Overall, the respondents split between fair to good in their ranking of the NYISO's ability to implement the PRL programs, based on last summer's experience. Some explicitly acknowledged the constraints under which the NYISO labored, but indicated that the late program approval contributed to the already challenging task of introducing customers to, and demonstrating the value of, this new retail electricity-purchasing proposition in a short period of time.



Summary

The NYISO accomplished what it set out to do in launching PRL pilot programs. The programs attracted widespread participation by customers of many sizes and circumstances. It demonstrated that customers' load management actions could be fully integrated into the market operations of an ISO. EDRP provided over 425 MW off emergency resources when system reserves were needed to prevent forced load shedding, generating reliability benefit well in excess of payments to Participants. Collateral benefits include lower real-time prices during events, and pressure on RTM prices that affects bilateral market clearing prices.

	EDRP	DADRP
Total Participants	292	16
Total Subscribed Load	712 MW	134 MW
Max. Hourly Curtailment	425 MW	25 MW
Total Program Payments	$ 4.2 Million	$ 0.2 Million
Reliability Benefits to Payments Ratio	4.5:1 - 9.5:1	N/A
Collateral Benefits	$ 13.0 Million	$ 1.5 Million
Range in Avg. Reduction in LBMPs	0.50 - 1.42/MWH	0.12 - 4.12/MWH
Estimated Hedging Cost Benefits	$ 3.9 Million	$ 0.7 Million

DADRP curtailment bids were evaluated along side the day-ahead supply bids of generators and scheduled when they offered a lower cost solution to meeting the market's supply needs. They provided 25 MW of load reductions at the peak price hour and contributed to lower DAM price volatility, which generates benefits to all electricity purchasers.

An important result of this work is the development and application of an overall framework for ascertaining the level and distribution of benefits arising from PRL programs that are fully integrated into the NYISO's market operations. Familiar but abstract theoretical representations of the value of PRL resources were rigorously quantified for the first time. Supply models that accurately characterize the unique nature of electricity markets were developed and applied to periods when PRL curtailments were undertaken to estimate market impacts. The DADRP, and to a lesser extent the EDRP, were found to have contributed measurably to reducing market price volatility, despite the small size of PRL resources relative to the total load served. A little bit does indeed go a long way, when properly used.

Market research initiatives provided customers with an opportunity to be heard. Survey responses provided compelling insight into how customers perceive the opportunities PRL programs offer. The good news is that customers are capable of evaluating PRL programs that are, by necessity, technically complex provided that they receive information packaged to fit their situation and that stresses the value and risks that constitute participation. The survey confirmed that not all customers can or want to participate, so the key to marketing the programs is to be able to cost-effectively target marketing initiatives to those most likely to participate.

Behavioral models were estimated to capture and quantify customers' revealed and stated preferences, the results of which provide a foundation for designing and implementing programs that will have a lasting impact on the market. Response elasticities, estimated for individual Participants, provide insight into what kinds and sizes of customers can profit from PRL participation. The results suggest that PRL programs of this ilk will be popular over a wide range of customer circumstances and provide a diversified and reliable portfolio of resources that contribute to market liquidity.

Much has been learned, including that the education process itself must continue. The entities responsible for marketing PRL programs to end-use customers were valuable critics, offering recommendations that will serve to expand participation and improve the responses of those subscribed to programs. The existing product designs require no major overhaul as they go into the second year of availability. Maintaining a consistent design, at least throughout the pilot, leverages investments in infrastructure made by the NYISO, and by the LSEs and CSPs that deliver these program opportunities to end-use customers. Moreover, program continuity lays the foundation for more precisely measuring market impacts and establishing program benefits over time.

However, there are several exigencies regarding how the programs are administered. A more robust definition of the customer baseline load will help customers understand and accept it as the foundation for measuring curtailment performance. Accommodations to recognize the unique circumstances of customers with highly weather sensitive loads will open up new and potentially valuable PRL resources. Provisions for an alternative means of establishing what the level of usage would otherwise have been will have appeal to very large and very small customers. The former will be better able to focus attention to controlling a single process. Statistical measurement will open up participation to residential and smaller business for which the costs of detailed metering act as a barrier.

Projections of potentially tight supply conditions of another year or two necessitate maintaining, and possibly increasing, participation in EDRP. But, the long-term benefits from more routine, customer-managed curtailment transactions associated with DADRP argue strongly for focusing attention to factors that currently limit participation. To accomplish this end, education and training are paramount. LSEs and CSPs must themselves be thoroughly in command of how DADRP bids are evaluated in order to develop and administer training programs intended to educate customers. Issues attendant to the availability and use of DADRP bid slots raised by the LSEs, and new concerns voiced by CSPs, that starting in 2002 will also market DADRP programs, need to be addressed and resolved to both increase participation and sharpen the bidding strategies of Participants.

Finally, the NYISO PRL programs should not be operated in a vacuum and be evaluated myopically. Others share the commitment to increasing customer participation in electricity markets by making access available through ISO administered PRL programs. The NYISO should be forthcoming with the results of its program analyses, in order to take advantage of the value of critical review. Doing so will ensure that the full value of PRL resources will be realized throughout US electricity markets, and that the NYISO's market Participants are the first to fully realize them.

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January 15, 2002