Price Responsive Load Programs in the New York Wholesale Electricity Market

Peter W. Douglas, J. David Coup, and Daniel Osei-Antwi
New York State Energy Research and Development Authority

ABSTRACT

This paper will discuss the design and operational performance of Price Responsive Load (PRL) programs administered in the New York wholesale electric market by the New York Independent System Operator (NYISO). Topics covered include the NYISO structure, PRL design and operation, performance of NYSERDA companion programs, and an evaluation of the results.

Wholesale Market and New York Independent System Operator

The New York utility market is moving towards a fully competitive model, pursuant to orders initiated by the Federal Energy Regulatory Commission (FERC) and the New York State Public Service Commission (NYSPSC). By 1998, under FERC Order 888/889, transmission services were to be provided on an open access basis and a wholesale energy market was to be created. In parallel, the NYSPSC negotiated settlements with each regulated utility whereby full retail access was to be available to all customers by 2001 and structural separation and divestiture of generation assets by utilities was to be completed by 2002. Also pursuant to the FERC Order, the New York Independent System Operator (NYISO) was created and began operation in November 1999. The NYISO's mission is to operate an efficient and non-discriminatory wholesale electric market and maintain reliability of New York's electric system. The former regulated market that consisted of vertically integrated utilities has been replaced by a collection of entities that independently provide generation, transmission and retail distribution.

Zones and Reliability Requirements

The NYISO manages the New York Control Area (NYCA) that consists of all New York territories formerly served by the regulated utilities. The NYCA is bounded by and conducts power transfers with other US and Canadian control areas. The NYISO has organized the NYCA into eleven geographical zones that reflect the existing topography of transmission lines, load centers and generation facilities.

For reliability purposes, the NYISO maintains a system-wide 18% reserve margin between peak loads and available in-state capacity. Since 1999, New York's overall in-state capacity has not been able to meet the 18% reliability reserve requirements without importing power from adjacent control areas. The cause has been greater than expected load growth and difficulty in siting new generation or transmission capacity within New York. Purchases from outside of New York and interruptible resources are now required to maintain reliability standards.

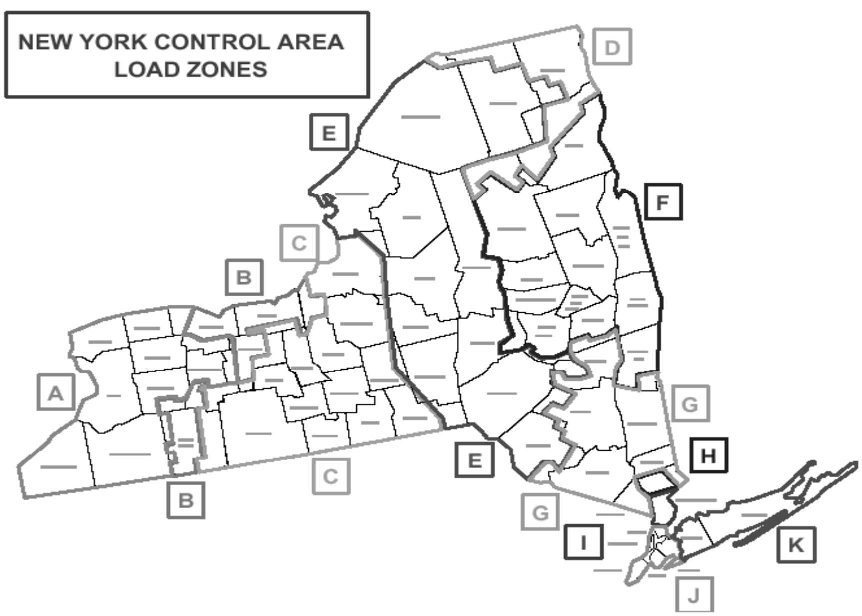
In addition, the NYISO also imposes in-zone generation capacity requirements in certain zones because of limitations in transmission capacity to import power. Specifically, the high load-density downstate areas of New York City (Zone J) and Long Island (Zone K) have in-zone generation capacity requirements of 80% and 107%, respectively. This amounts to a potential capacity shortfall of 600+MW during peak periods, without taking into consideration the 18% reserve requirement (Table 1). During summer peak periods, the combined effects of in-State and in-zone capacity shortfalls can result in extreme energy prices and reduced reliability, particularly in the downstate areas.

Table 1. Zonal Peak Loads, Capacity and Reserve Requirements, 2000

Zones	Demand		Supply	Location-Based Capacity Requirements		
	Peak (MW)	Peak + 18% Reserve (MW)	Installed Capacity (MW)	In-Zone (% of Pk.)	In-Zone (MW)	Shortfall (MW)
Western - A,B,C,D,E	9,140	10,785	14,693	Na	Na	Na
Hudson River -F,G,H,I	6,156	7,264	8,116	Na	Na	Na
NYC – J	10,340	12,201	8,031	80%	8,272	-241
Long Island -K	4,564	5,386	4,507	107%	4,883	-376
Total	30,200	35,636	35,347			-617

Source: NYISO et al. 2001

Figure 1. NYCA Zone Map



Source: www.NYISO.com

Market Participants and Price Determination

The market function of the NYISO is to manage an orderly discovery of prices and exchange for capacity, energy, ancillary services and transmission. The primary market participants are Generators, Load Serving Entities (LSE), Direct Customers (DC), Customer Service Providers (CSP) and Transmission Owners (TO).

Generators sell installed capacity (ICAP), energy and ancillary services (reserves, voltage/frequency regulation, and black start). Ancillary services are competitively procured by the NYISO from Generators and allocated to LSE's and DC's according to relative loads. TO's derive revenue by auctioning the rights to transmission service and transmission congestion charges paid by LSE's and DC's.

LSE's buy ICAP and energy and sell these services to end-users. DC's are large customers who buy ICAP and energy directly for their own use. LSE's are either: regulated subsidiaries of the former utilities and providers of last resort; or new unregulated service providers. The holding companies which own regulated LSE's also own the TO's. The regulated LSE's provide 95% of retail service.

CSP's sell the aggregated energy curtailment from end-users that have procured energy from other LSE's. The CSP was introduced to increase load curtailment participation by end-users where the LSE might not offer this capability. Only regulated LSE's are required by the NYSPSC to offer load curtailment programs to end-users, however unregulated LSE's offer these programs to increase business. CSP's face less stringent financial requirements by the NYISO than other market participants.

LSE's, CSP's and DC's can also sell capacity and energy into the wholesale market in the form of a commitment to curtail load on demand.

The types of energy trading occurring in the New York energy market consists of bilaterals (50% of volume), day-ahead market (45-50% of volume) and real-time market (5% of volume). Bilaterals are direct trades between generators and LSE's at undisclosed prices.

The ICAP market is settled no later than the month in which energy consumption occurs. ICAP can be bought or sold in 1 month and six-month strips. On average, ICAP costs vary from $1/kW-Month to $9/kW-Month in the areas having in-zone capacity deficits.

The day-ahead market (DAM) determines hourly prices in each zone and is the interaction of an upwardly sloping supply curve (marginal generation cost) and a vertical demand curve (aggregate forecasted load). The clearing price for this market is referred to as the DAM-Location Based Marginal Price (LBMP). The real-time market (RTM) serves to balance differences between planned (day-ahead) requirements and actual (hour ahead) usage. The RTM-LBMP exhibits greater volatility than the DAM-LBMP.

Because of sheer volume, the DAM-LBMP has the greatest impact on the energy prices that all customers pay. The DAM-LBMP has averaged $58/MWh since the NYISO began operations. During extreme summer peaks conditions, the DAM-LBMP can spike sharply to levels in excess of $500/MWh. While the RTM-LBMP is more volatile than the DAM-LBMP, it represents a smaller fraction of an average customer's energy costs. LSE's and DC's hedge risk by limiting exposure in the RTM in favor of the DAM and bilateral contracts.

Price Responsive Load Programs

Recognizing the potential for summer peak loads to trigger capacity shortfalls, the NYISO formed the Price Responsive Load Working Group (PRLWG) in the late summer of 2000. The PRLWG is composed of representatives from each type of market participant, NYSPSC and the New York State Energy Research and Development Authority (NYSERDA). The PRLWG's mission is to develop programs that provide financial incentives to end-users for removing load from the system during extreme conditions to avoid emergencies and high prices. The PRLWG benefited from members who were also market participants in the adjacent Pennsylvania-New Jersey-Maryland and New England ISO control areas, where similar programs were being discussed. Two programs were established: the Emergency Demand Reduction Program (EDRP) in January 2001 and the Day-Ahead Demand Reduction Program (DADRP) in May 2001. The DADRP allowed load reductions to be bid into the DAM, and the EDRP provided the means for dispatchable load reduction in response to conditions arising after the DAM had settled. Both programs provide financial incentives for load curtailment and are supported by common charges to all DC's and LSE's. The performance of these programs is measured in terms of load reduction to maintain reliability and the associated cost-benefits.

The EDRP provides incentives for performance in response to a NYISO declared emergency. The program is voluntary, but end-users must register with the NYISO to be eligible for performance payments. Load curtailment could be from back-up generation or by shutting down equipment. Payment is the greater of $500/MWh or RTM-LBMP for each hour of the declared emergency period. The EDRP program would impact RTM-LBMP, since the emergency would have been declared following the determination of DAM-LBMP.

The DADRP program allows for demand response to be bid into the DAM. Payment is the greater of bid price or DAM-LBMP plus curtailment initiation costs. Performance is mandatory and penalties are assessed for non-performance. If a bid is accepted, then end-user cannot purchase energy in the RTM. Diesel generation was not allowed as an option under DADRP. The DADRP program will impact the DAM-LBMP.

The ICAP market also provided a third type of price responsive load program because load curtailment could be sold as though it were an increase in generation capacity. End-users can receive both EDRP and ICAP payments during a NYISO declared event, since ICAP is considered as capacity and EDRP as energy. ICAP events are called at the same time as EDRP events. To receive ICAP payments, the participant would have sold capacity covering the month in which the emergency event was called.

EDRP and DADRP payments are made to the LSE/CSP and are shared with each end-use customer that delivered load reduction according to private arrangements. Interval meters and a reference Customer Base Line (CBL) load are required to validate and determine payment. The features and benefits of the three programs are summarized in Table 2.

Table 2. Price Responsive Load Features and Benefits, 2001

	Market Function	Eligibility	Event Notice	Duration	Up-Front Payment	Performance Payment	Non-Compliance Penalty
EDRP	Emergency Energy	>100kW, can aggregate	Day-ahead warning, 2 hour event notice	Min. of 4 hours	None	Greater of $0.50/kWh or RTM LBMP	None
DAD RP	Economic Energy	1 MW Can Aggregate	Bid By 5am DAM, Notice by noon	As bid, can require strip	None	Greater of Bid $/kWh or DAM LBMP	Greater of DAM or RTM LBMP, plus 10%
ICAP	Installed Capacity	>100kW	Day ahead warning, 2 hour notice	As needed	$/kW, market value of ICAP	None	Penalty, derating
All programs require interval meter with 2% accuracy or better All programs require a Customer Baseline Load based on prior weekday's usage Diesel generation not allowed for DADRP							

Source: Lawrence et al. 2001-2002

NYSERDA Programs

Concurrent with the introduction of the EDRP and DADRP, NYSERDA initiated programs to provide financial and technical assistance to increase participation in the NYISO programs. The NYSERDA programs, Enabling Technologies and Peak Load were announced in January 2001 and required installation prior to the beginning of the 2001 summer peak load season. These programs were designed to reduce risks by offsetting curtailment-enabling costs, since revenue streams would be unpredictable.

The Enabling Technology Program, managed by the research and development department, provided financial support for innovative technology (communications, networking, remote metering) and organizational structures which improved end-use aggregation by LSE/CSP's. Innovative proposals were competitively selected and funded to a maximum of $150,000. The Peak Load Program, managed by the deployment department, provided financial support for modifications to on-site equipment such as upgrades to energy management systems, lighting and air conditioning controls, emergency generator switch gear and interval meters. Funding was provided, on a subscription basis, up to a maximum of $125 per curtailable kW of installed equipment. Both programs required 50% cofunding by proposers. NYSERDA also heavily promoted the programs through workshops, printed information and the internet.

The NYISO and NYSERDA jointly commissioned Neenan Associates to provide an evaluation of the performance of the PRL and companion NYSERDA programs following the completion of their first year of operation. Both programs will be modified ahead of the 2002 season to increase performance and participant satisfaction.

Summer 2001 Performance

During August 2001, higher than normal temperatures forced the NYISO to invoke emergencies on August 7, 8 and 9 (18 hours in all zones) and on August 10 (4.5 hours in NYC/Long Island and Hudson River, Zones F-K). On August 9^{th}, a new record peak load of 30,983 MW was established. Most of the capacity shortfall occurred in the NYC/Long Island area (Zones J-K). During this time, a variety of load management programs including the PRL programs (EDRP, DADRP, and ICAP) were deployed. At peak load, an estimated 1580 MW was curtailed, of which the PRL programs contributed 605 MW (38%) and the balance coming from other sources (Table 3). The significance of the PRL programs is increased by the fact that they were easily measured, while other load reduction sources (public appeals, government) were not.

Table 3. Total Demand Response by Source, Peak Hour 8/9/2001

Source	(MW)	Measurement Accuracy
EDRP-ICAP (1)	580	High
DADRP	25	High
Voltage Regulation	350	High
Utility Programs (2)	135	High
Public Appeals (3)	270	Low
NYS Government (4)	220	Low
Total	1,580	

(1) NYISO allows simultaneous participation EDRP and ICAP. Some load was in only one or both programs.
EDRP-ICAP (580MW)=EDRP only (260MW) + EDRP/ICAP (160MW) + ICAP only (160MW)
(2) Administered by LSE's in the local territories and included direct load control and interruptible supply.
(3) Voluntary uncompensated actions.
(4) Reduce building energy use or shut down entire office.

Source: Klapp et al. 2002

EDRP Performance

At the time the EDRP events were called, 292 participants had registered in the EDRP. About 72% did so through an LSE and a quarter subscribed through a CSP. Participation in the upstate areas was largest, owing possibly to more aggressive marketing and coordination by the LSE's and CSP's covering this region (Table 4). NYSERDA's effort to increase EDRP participation was more successful in upstate areas (41%) than in downstate areas (16%) (Table 4).

Participants in the EDRP provided 70% of all load curtailment from all PRL programs. While 292 participants (712 MW) registered with the NYISO for EDRP, only 213 (617 MW) actually performed when emergencies were declared. Those who performed only delivered an average 418 MW per hour or 68% of their registered capability. A planning consideration for future rounds of the EDRP, given that it is a voluntary program, is that more load has to be registered than is actually required.

The NYSERDA programs focused on smaller participants, who for risk aversion and less technical capabilities were unlikely to participate in the absence of government assistance. Even though the NYSERDA-assisted participants provided only 23% of the registered load, they delivered 26% of actual curtailed load (Table 5).

Table 4. Zonal Distribution of EDRP Registration by Market Participants

Region (1)	Zone (2)	LSE	CSP	Other	Total		NYSERDA (3)	Other (4)
		No.	No.	No.	No.	%	No.	No.
Western	A,B,C,D,E	106	1	6	113	38%	47	66
Capital	F	23	1	4	28	10%	6	22
Hudson	G,H,I	32	13	0	45	15%	13	32
NYC/LI	J,K	49	57	0	106	36%	17	89
Total		210	72	10	292	100%	83	209
%Total		72%	25%	3%	100%		28%	72%

(1) Regions of the state which contain one or more zones
(2) NYISO zone designations
(3) PRL participants that received financial assistance from NYSERDA to enable load curtailment
(4) PRL participants that did not receive any NYSERDA funds

Source: Neenan et al. 2001

Table 5. EDRP Planned vs. Actual Participation

	Units	NYSERDA	Other	All
Registered for EDRP (1)				
-Sites	No.	83	209	292
-Load Curtailment Capability	MW	167	545	712
Participated in EDRP Events (2)				
-Sites	No.	59	154	213
-Load Curtailment Capability	MW	145	472	617
Actual Participation Levels (3)				
-Maximum Curtailment Hour	MW			425
-Average Hourly Curtailment	MW	102	316	418
-Total Energy Curtailment	MWh	2118	6014	8132
-Load Curtailment Share of Total	%	26%	74%	100%
-Percent of Registered Load	%	70%	67%	68%
-Average Curtailment/Site	MW	1.73	2.05	1.96

(1) All participants who registered for EDRP.
(2) Subset of registered participants that performed during EDRP events.
(3) Actual performance during events. Typically less than registered capability.

Source: Goldman, Grayson, Kitner et al. 2002

On average, upstate participants curtailed a disproportionately larger share of load (38% of registered sites vs. 64% of total MWh) than downstate participants (36% of registered sites vs. 12% of total MWh). Nearly 85% of total hourly curtailment came from participants who exclusively reduced load, while only 15% came from participants that used on-site generation or a combination of both. However, those who exclusively reduced load, curtailed about 5% of their total load, while those with on-site generation were able to contribute substantially more.

EDRP participants received \$4.2 million in payments for 8,159 MWh of load curtailment. All NYISO market participants who purchase energy received substantially larger benefits in the form of reductions in RTM-LBMP costs and volatility, and an increase in reliability. RTM supply curves based on NYISO data were modeled to estimate these benefits. The effect of load curtailment in various zones is estimated to have reduced RTM load by 0.1-3.3% and RTM-LBMP by 0.6-29% for a $12.9 million energy cost savings. Since EDRP also contributed to reducing volatility, hedging costs in the RTM were reduced for all by $3.8 million (Table 6).

EDRP also improves reliability by restoring capacity reserve levels through load curtailment, which in turn decreases the Loss of Load Probability (LOLP). EDRP improved system reserve margins from 34% to 59%, with a proportionate decrease in LOLP. To estimate the value of LOLP, it was assumed that 5% of total load was at risk of interruption and the value of an outage was $1000/MW. A conservative estimate of the value of LOLP is $384,000 per MWh curtailed or a total of $6.2 million for the 18 hours of emergencies for all zones.

Table 6. EDRP Effects on RTM Load, Price and Volatility

	RTM Load			EDRP	RTM-LBMP		RTM-LBMP Hedging	
	Avg. Hourly Chg.		Total Change	Total Payments	Avg. Hourly Change	Total Cost Reduction	Mean Price Difference	Reduced Hedging Cost
Area	MWh	%Chg.	MWh	$,000's	%Chg.	$,000's	$	$,000's
Western	63	3.3%	5,276	$2,674	21.5%	$ 6,359	$1.91	$1,880
Capital	37	3.1%	1,446	$747	28.8%	$ 3,036	$4.05	$851
Hudson	6	0.5%	430	$223	3.8%	$ 906	$0.60	$243
NYC	293	0.4%	860	$431	4.1%	$ 2,439	$0.66	$832
LI	19	0.1%	148	$101	0.6%	$ 214	$0.12	$62
Total			8,159	$4,167		$ 12,954		$3,868

Source: Neenan et al., 2001

About 38% of performing EDRP load curtailment also received ICAP payments for the same load as additions to capacity. Depending on the zone, the ICAP payments for the same load would have added 100-400% to total payments. This is illustrated in Table 7.

Table 7. Comparison of EDRP and ICAP Load Curtailment Payments

	EDRP Payments (1)				ICAP Payments(2)				Total
	Energy	Rate	Time	Pay-ment	Capacity	Rate	Time	Pay-ment	Pay-ment
Zones	(kWh)	($/kWh)	(Hours)	($)	(kW)	($/kW-M)	(Month)	($)	($)
Western	1,000	$0.50	18	$9,000	1,000	$1.9	6	$11,400	$20,000
NYC	1,000	$0.50	23.5	$11,750	1,000	$8.75	6	$52,500	$64,250
(1) EDRP Payments based on $500/MWh minimum. Time is actual duration of emergency in each zone.									
(2) ICAP payments based on 6-month capacity strips and observed ICAP payments during summer 2001.									

DADRP Performance

Participants in the DADRP provided the smallest contribution to total load reduction by the PRL programs (maximum 25 MW on 8/9/2001). Sixteen participants had multiple bids accepted into the DAM over a 30-day period (7/20 thru 8/27). Participation occurred in two zones within the Western and Capital areas.

DADRP participants received $217,000 in payments for 2,694 MWh of load curtailment. The effect of load curtailment in various zones is estimated to have reduced DAM load by 0.3-0.9% and DAM-LBMP by 0.2-0.3% for a $1.5 million energy cost savings. Hedging costs in the RTM were reduced for all by $650,000 million (Table 6).

Lower levels of participation were attributable to reduced revenue opportunities, steep penalties for non-performance and late program start (5/01). The largest opportunities for gains occurred when emergencies were anticipated. On these days, the DAM-LBMP would reach higher levels, so a high curtailment bid was more likely to be accepted. However, on non-emergency days when DAM-LBMP prices were lower, a successful DADRP bid would be so low that the opportunity cost of curtailment could not be offset.

Table 8. DADRP Effects on DAM Load, Price and Volatility

	DAM Load			DADRP	DAM-LBMP		DAM-LBMP Hedging	
	Avg. Hourly Chg.		Total Change	Total Payments	Avg. Hourly Change	Total Cost Reduction	Mean Price Difference	Reduced Hedging Cost
Area	MWh	%Chg.	MWh	$,000's	%Chg.	$,000's	$	$,000's
Western	5	0.3%	1,463	$83	0.3%	$ 458	$0.51	-
Capital	3	0.2%	1,231	$134	0.9%	$ 1,029	$1.42	-
Total			2,694	$217		$ 1,487		$650

Source: Neenan et al. 2001

Curtailment Methods and Demographics

The methods used by LSE'/CSP's to aggregate end-users and bring curtailable load into the wholesale market where: (1) technologies to manage information between the LSE/CSP and the end-user; and (2) on-site monitoring and control equipment. LSE/CSP investments included Internet-based software that provided near real-time interval load data, calculation of CBL, bids and NYISO payments. On-site requirements included interval meters, modifying building energy management systems, switchgear for back-up generators, and upgrade of controls for lighting and other energy using equipment. While 42% of end-users made no on-site modifications, the most frequent preparation was the development of a load curtailment strategy (Table 9). Because 29% of end-users had participated in previous time-of-use programs, they were well prepared to develop strategies. The primary load curtailment strategies employed were to turn down or shut off lights; halt major production processes or alters the building temperature. Shutting down plant operations entirely occurred less frequently.

The largest contributors to load curtailment came from manufacturing and telecommunications industries that were capable of shutting down, rescheduling shifts and/or running back-up generation. NYSERDA bought a number of small manufacturing and service type buildings into the program, where curtailment options were limited to reducing lighting and air conditioning loads (Table 10)

Table 9. Preparation and Actions by EDRP Participants

Preparations Taken For EDRP		Actions Taken During EDRP Events	
Type of Measure	Frequency	Type of Action	Frequency
None	42%	Turn Down/Off Lighting	27%
Load Management Strategies	19%	Halt Major Production Processes	25%
Interval Meters	17%	Alter Building Temperature	19%
Internet- Remote Monitoring	15%	Use On-site Generation	17%
Load Control Devices	5%	Shut Down Plant	7%
On-Site Generators	1%	Other	5%
Other	1%		

Source: Neenan et al. 2002

Table 10. Distribution by Peak Load Size and Industry Type

By Peak Load Size		By Standard Industrial Classification		
Peak Load	(%)	Description	SIC	(%)
<250 kW	14%	Manufacturing	02-39	38%
250-500kW	10%	Communication, Utility	48-49	21%
500kW-1MW	17%	Wholesale, Retail	50-56	5%
1-4MW	39%	Commercial Services	60-79	15%
>4MW	20%	Health Services	80	7%
		Education Services	82	3%
		Other	83-99	10%

Source: Neenan et al. 2002

Cost Benefit Analysis

The cost and benefits of PRL programs is evaluated from a broad perspective of all NYISO market participants and a narrow perspective of all PRL participants (Table 11).

The first group consists of the NYISO market participants including those who directly participate in the PRL program. The market benefits to this group are explicit (reduced price, volatility, avoided energy and capacity charges) and implicit (improved reliability). The cost to this group include the uplift all market participants will pay to finance the PRL program, and the enabling costs (aggregation, on-site modifications) that PRL participants (LSE/CSP's, end-use customers) must pay by themselves. In this case, the most conservative benefit-cost ratio is 1.35 since the discounted value of future benefits from repeat emergencies is not included. The group's investment in enabling costs can be recovered in less than one year.

The second group consists of the PRL program participants exclusively. For this group, certain cost and benefits that NYISO market participants see are reduced according to their relative contribution to peak load. It is assumed that PRL participants curtail 5% of their peak load, so their total peak load is 8,500 MW (425 MW/ 0.05). Therefore, their share of market benefits is 27.5% (8,500 MW/ 30,900 MW). At the same time, this group receives 100% of total PRL payments, the relative size of which increases. In this case, the most conservative benefit-cost ratio is 0.73. The group's investment in enabling costs can be recovered in a little more than one year.

While benefit-cost ratio for the PRL participants seem favorable, it may be too low to attract new curtailable load in future years. A large amount of curtailable load from large, sophisticated users has already been acquired and much of this load incurred little cost to enable (42%, Table 9). The low hanging fruit may be gone. To attract additional curtailable load will require acceptable economics for both the LSE/CSP's and end-users.

The NYSERDA program, which catered to smaller, less sophisticated end-users, saw average enabling cost in the $40-80/kW range. The average PRL payment last summer for curtailment was $0.56/kWh for 23.5 hours of events. To recover enabling costs would require 3 to 6 years assuming the same level events. This may not be an attractive proposition for end-users.

LSE/CSP's can face substantial cost marketing the PRL programs. End-users have to equip themselves with new equipment. Revenue streams have to be shared between both parties. On a positive note, many end-users benefited from the quality of information gained from investment in interval meter and internet-based monitoring services. They were able to identify other cost-effective energy efficiency improvements. Some of the smaller LSE's were able to forecast load customer requirements faster and more accurately, thereby reducing their risk in the RTM. This should increase their competitive position with the incumbent POLRs.

Table 11. Comparison of Cost-Benefits by Participant Group

		NYISO Market Participant (1)	PRL Program Participant (2)
		($,000's)	($,000's)
Cost	EDRP.Uplift (3)	$4,167	$1,146
	ICAP.Uplift (3)	$398	$109
	DADRP.Uplift (3)	$54	$15
	Enabling Cost (4)	$20,114	$20,114
Benefits	EDRP.RTM (5)	$23,086	$6,351
	DADRP.DAM (5)	$958	$12
	PRL Payments (6)	$4,169	$4,169
	Avoided Energy(7)	$4,221	$4,221
	Avoided Capacity(7)	$398	$398
Total Costs		$24,733	$20,384
Total Benefits		$33,282	$15,601
BC Ratio		1.35	0.73
Payback (Yrs)		0.74	1.37

(1) All NYISO Market Participants (includes PRL participants).
(2) PRL program participants only.
(3) When EDRP, DADRP & ICAP are treated as group costs financed by uplift to all market participants.
(4) Costs to PRL program participants and their customers.
(5) Value of explicit (reduced price, volatility) and implicit (improved reliability) benefits to the group.
(6) EDRP, DADRP & ICAP payments as a revenue stream (benefit) to PRL program participants.
(7) When energy and load is curtailed, participants also see a reduction in the costs of approximately the same value as the PRL payments.

Survey of PRL Program Participants

Surveys of the PRL and NYSERDA program participants and non-participants were conducted to learn about their perceptions of the programs. About one-third of PRL program participants were included in the response. Most respondents were satisfied with the EDRP program, but the DADRP participants were considerably less satisfied. Issues reducing DARRP's attractiveness were its mandatory performance requirement, the 1MW minimum bid size requirement, diesel generation exclusion and bid slot allocation. Points of dissatisfaction for both PRL programs included the CBL calculation methodology (no weather adjustment), expense of the interval meter requirement and the administrative burden of aggregation. Reasons for not participating included finding out about the programs too late, and installing equipment or registering too late.

Conclusions

PRL programs implemented by the NYISO performed well. They helped reduce energy costs and improve reliability for all NYISO market participants. The NYSERDA programs added additional load curtailment by focusing on end-users that would not have otherwise participated. While benefit-cost ratios are positive for the NYISO market participants as a group, they are less for the PRL participants. Benefit-cost are improved with the use of ICAP. Once enabled, end-users become more aware of energy use and are able to identify other energy efficiency actions that allow faster cost recovery. The costs of aggregation and enabling on-site load must be further reduced in order to improve the economics for this group. NYSERDA should continue to support innovation in aggregation methods and assistance to end-users.

References

Goldman, Charles, Hefner Grayson and Micheal Kitner. 2002. *Impact on Customer Load Curtailment Performance*. Lawrence Berkeley and Pacific Northwest National Laboratories. Berkely, CA; North Richland, Wash. : Lawrence Berkeley and Pacific Northwest National Laboratories.

Klapp, Kenneth M. 2002. *The Wholesale ElectricityMarket in New York State*. New York Independent System Operator (NYISO). Albany, N.Y.: New York Independent System Operator.

Lawrence, David (New York Independent System Operator). 2001-2002. Personal Communications. 2001-2002.

Neenan, Bernard F., Donna K. Pratt, Peter A. Coopers, Richard N. Boisvert, and Kenneth R. Deal. 2001. *NYISO Price-Responsive Load Program Evaluation Final Report.* Neenan Associates, L.L.C. Syracuse, N.Y.: Neenan Associates, L.L.C.

New York Independent System Operator (NYISO). 2001. *Power Alert*. Albany, N.Y.: New York Independent System Operator.

New York Independent System Operator (NYISO). 2002. *Power Alert II*. Albany, N.Y.: New York Independent System Operator.