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2004 NYISO Demand Response Program Evaluation

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Executive Summary

The New York Independent System Operator (NYISO) has offered demand response programs for the past four years. Retail customers, through an enrolling agent, can offer curtailable load as a resource into NYISO's day-ahead spot market and monthly installed capacity auctions. Demand response resources that are scheduled in the day-ahead market or sold in an installed capacity auction are fully integrated into market operations and therefore are paid and influence market-clearing prices. Failure to fulfill a curtailment obligation results in the assessment of penalties, which can be substantial. In addition, curtailable loads can be enrolled as emergency resources that are called upon on an as-available basis to forestall conditions that lead to load-shedding. Such curtailments are voluntary, are paid the greater of the prevailing real-time market price or a predetermined floor price, and may set the real-time market spot price.[1]

The NYISO has commissioned an independent study of the performance of these programs each year.[2] This report describes the results of the evaluation of the performance of the 2004 DR programs, supplementing the materials included in the NYISO's December 2004 topical filing with the FERC. [3] The program analyses utilizes methods and protocols, developed to conduct pervious years' programs, which quantify the level and distribution of benefits that result when demand response resources are called upon to curtail.

A total of 1,939 MW of resources were enrolled in 2004, distributed as follows; 20% (377 MW) in the Day-Ahead Demand Response Program (DADRP), 51% (981 MW) in the Installed Capacity/Special Case Resources (ICAP-SCR) program, and 29% (581 MW) in Emergency Demand Response Program[4] (EDRP) by 17, 933, and 1097 program participants, respectively. The average curtailment per participant for the EDRP, and ICAP programs was 516 KW and 1,054 KW, respectively. ICAP-SCR program participants are generally larger than those in EDRP. The equivalent value for DADRP,

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[1] Complete program provisions are available at www.NYISO.com, on the home page select *Demand Response Program Information.*

[2] Ibid.

[3] New York Independent System Operator, Inc. December 1, 2004. *Seventh Bi-Annual Compliance Report on Demand Response Programs and the Addition of New Generation in Docket No. ER01.3001-0*0. Available at NYISO.com

[4] EDRP program values include ICAP program participants whose capacity was unsold (29 participants with 10.3 MW)

over 22 MW/participant, is not directly comparable since DADRP registrations probably reflect total load, not just the curtailment portion. Transmission Operators (TO) are responsible for enrolling 95% of EDRP participation, while Curtailment Service Providers and competitive Load Serving Entities enrolled over 85% of the load participating in ICAP-SCR.

Participation in NYISO's demand response programs was about the same as in 2003, but the character of enrollment changed. Enrolled ICAP-SCR load increased by 30% and participants increased by 44%. Participation and enrolled load in the other two programs decreased between 20% and 30%. This shift in enrollment likely reflects program changes implemented in 2003. Unlike previous years, where all available demand response resources were dispatched without considering how much was actually required, the new protocols call for the system operator to first dispatch as much of the available ICAP-SCR resource as are needed, and only if this amount is insufficient does it call for voluntary curtailments from EDRP participants. Some customers may have reckoned that the likelihood of having an opportunity to be paid to curtail under EDRP was diminished as a result, and elected not to participate. The EDRP has undergone considerable turnover in participation almost from its inception, in large part because the no penalty provision allows customers to enroll at no risk to get first-hand experience. Many appear to have learned from that experience that they are incapable of curtailing under the program's conditions. However, 2004 was the first year that total EDRP enrollment dropped.

Other program protocol changes were introduced in 2004, reflecting adjustments made to improve program performance by better integration of curtailments into NYISO market operations. A floor price of $75/MWH was imposed on DADRP curtailment bids to improve the program's performance, the result of an analysis that indicated that bids at lower prices were not welfare improving. Shortfalls in meeting scheduled DADRP curtailment obligations were settled at the prevailing real-time LBMP, which corresponds to how scheduled generating shortfalls are treated. Previously, settlement was at the higher of the day-ahead and real-time LBMP.

No curtailments were called for in 2004 from either ICAP-SCR or EDRP participants. This is in contrast to the previous three years in which two to three different curtailment events were declared each year for a total of 10-22 hours. These curtailments produced from $7-35 million in benefits to consumers.

The NYISO spot markets continued to show a decline in overall price volatility and the number of prices that exceeded $75/MWH. As a result, fewer curtailments were scheduled under the DADRP program than in previous years, and the net benefits were lower. Total market bill impacts, the sum of direct bill savings and reduced hedging costs that inure to the collective market, were estimated to be about $46,000, only 12% higher than the payments made to participants for curtailments. In contrast, in 2001 estimated DADRP benefits were over $1.5 million, seven times the level of payments.

A new performance metric was introduced in 2004 to provide a measure of the changes in new social welfare attributable to the DADRP program. Bill savings represent transfers of money from generators to consumers, a redistribution of market outcomes that is not universally accepted as being beneficial. An alternative, and generally accepted, measure is the change in welfare that results when customers face prices that reflect marginal supply costs, instead of average rates, which is what DADRP accomplishes. The resulting changes in consumption reduces resource misallocations, referred to as dead- weighted losses, that result when customers make consumption decisions on prices that do not reflect the marginal cost of supply.

The estimated change in welfare in 2004 from DADRP curtailments was estimated to be about -$27,000, an unexpected result given the DADRP program objectives. Most of the scheduled DADRP bids, and they were few in number and never resulted in more than five MW being scheduled in any hour, were at LBMPs just above the $75/MWH floor price. The low LBMP corresponded to a relatively flat section of the supply curve. So, the discrepancy between the marginal supply cost and the average cost-based prices was small, and therefore the reduction in deadweight losses was small.

The negative overall welfare change is because the sum of these deadweight losses was less than the cost of achieving them, the payments made to customers that curtailed. In some hours, curtailments were scheduled at prices that produced a positive net welfare change, but the low price volatility in the day-ahead market resulted in these instances being few and far between. In fact, the $75/MWH bid floor was introduced specifically to reduce instances of scheduled bids that produced negative welfare changes. However, eliminating them altogether would require imposing a much higher floor price, and other bidding restrictions, that could act to deter program participation.[5]

[5] This issue was addressed by ISO-NE in the design of its day-ahead curtailment bidding program. See: Compliance Filing of the New England Power Pool Participants Committee and ISO New England Inc., FERC Docket No. ER04-1255. February 18, 2005.

The welfare loss can be considered as a kin to price volatility insurance premium. In order to have customers enrolled in DADRP and offering load curtailments as resources in times when market conditions produce high LBMPs, and curtailments are scheduled, there must be sufficient incentives to attract and retain customers during periods of low prices. For some, this requires that they can bid at be scheduled at relatively low LBMPs coincident to times when their outage costs are even lower. The welfare losses attributable to the DADRP program in 2004 appear to be minuscule when compared to the large potential gains if price do become more volatile.

1 Program Description

Program Provisions

Reliability Programs

NYISO offers two demand response programs to support reliability: the Emergency Demand Response Program (EDRP) and the Installed Capacity-Special Case Resource Program (ICAP-SCR).

The Emergency Demand Response Program (EDRP) provides resources[6] an opportunity to earn the greater of $500/MWh or the prevailing LBMP for curtailments provided when the NYISO calls from them. There are no consequences for enrolled participants that fail to curtail. EDRP curtailments, until this year, were called in conjunction with the dispatch of ICAP/SCR curtailments.

The ICAP-SCR program allows customers that can meet certification requirements to offer unforced capacity (UCAP) to LSEs and to the six-month strip and the monthly reconfiguration auctions that the NYISO operates. Resources are obligated to curtail when called upon to do so with two or more hour's notice, provided that they were notified the day ahead of the possibility of such a call. In addition, ICAP-SCR resources may be subject to testing to verify that they can fulfill their curtailment requirement. Failure to curtail could result in penalties administered under the ICAP program that can exceed the amount the participant received initially as an ICAP payment. Curtailments are called when reserve shortages were anticipated.

Day-Ahead Program

The DADRP program provides retail customers with an opportunity to bid their load curtailment capability into the day-ahead spot market as supply resources. Customers submit bids by 5:00 a.m. specifying the hours and amount of load curtailment they are offering for the next day, and the price at which they are willing to curtail. The bid price must be $50/MWH or higher. Bids are structured like those of generation resources, so DADRP program participants may specify minimum and maximum run times and effectively submit a block of hours on an all or nothing basis, which makes them eligible for production cost guarantee payments that make up for any difference between the market price during that block of hours and their block bid price. Load schedule in the

[6] A resource is defined as a single customer or an aggregation of customers enrolled in a program.

DAM is obligated to curtail the next day. Failure to comply results in the imposition of a penalty defined by the MW curtailment shortfall times the corresponding real-time market price.

Program Implementation

Prior to 2004, ICAP-SCR enrollments were made up of single retail customers and aggregations of participants that were counted as a single resource for program administration purposes. In 2004, NYISO made an administrative change to the way ICAP-SCR resources are enrolled resulting in each participant that is part of an aggregation being identified and tracked separately. Consequently, this year a more detailed characterization of ICAP-SCR enrolment can be provided. As a result, this year's ICAP-SCR program data cannot be compared directly with that of previous years.

Table 1-1 illustrates the results of tracking individual customers. Consider the first boxed columns, which represent total ICAP participation. Previously, enrollments were tracked as resources, categorized as either individual customer registrants or aggregations of customers. The table shows that under this classification total ICAP-SCR resources for 2004 are 268, comprised of 236 individually registered customers and another 32 aggregations that contain one or more individual customers. The new disaggregated system tracks participants, which correspond to individual metered customers. The table shows that the 32 aggregations contain 697 individual participants, and the total participation is 933 customers, over four times the number of reported resources. Since previous years' enrollments are reported in terms of resources, with aggregations, it is not possible to compare total participants under the new, disaggregated reporting with the number of resources reported in earlier years.

	ICAP			ICAP UnSold		
Aggregation Type	SCR-ID #	Participant #	Sold MW	SCR-ID #	Participant #	Subscribed MW
Non Aggregated	236	236	637.3	12	12	3.9
Aggregated	32	697	343.5	3	17	6.4
Total	**268**	**933**	**980.8**	**15**	**29**	**10.3**

Table 1-1 Detail of ICAP-SCR Participation by Resource Type

The second box provides the same information for unsold ICAP-SCR resources. ICAP-SCR registrants can sell their ICAP-SCR load to an LSE, or offer it into the NYISO ICAP auctions, once every six months for a six-month strip, and monthly reconfiguration auctions for strips of one to six months. In cases where an ICAP-SCR participant offers load to an auction but it is not taken, that load is automatically enrolled in the EDRP program until the next auction, or the participant completes a bilateral transaction with an LSE. As the table shows, in 2004 a very small percentage (1%) of registered ICAP-SCR load was transferred to the EDRP program.

2 Registration Summary

Program Participation

At of the end of August 2004, the reliability programs had a total of 2,059 participants enrolled providing a total of 1,562 MW of curtailable load.[7] There were 1126 resources in EDRP[8] and 933 participants in ICAP-SCR. Figure 2-1 and Figure 2-2 show the proportion of participation and enrolled MW by program, respectively. ICAP-SCR enrollments are 45% of the total but provide 50.6% of the curtailable load. EDRP had more participating customers, but they provided only 29.4% of the demand response resources. A small number of DADRP participants (1% of total program participants) accounted for 19.4 % of the demand response resources available. The average registered curtailable load for ICAP-SCR participants was 1,050 kW, twice that for EDRP (520 kW).

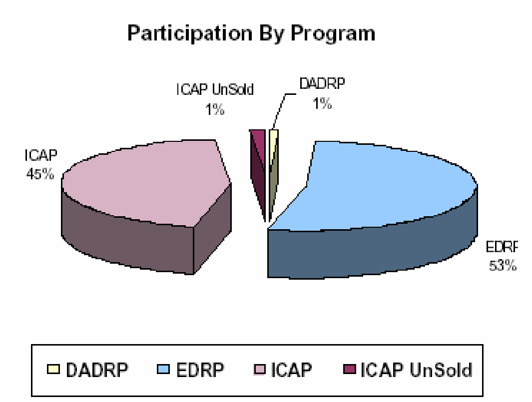


Figure 2-1 Participation by Program

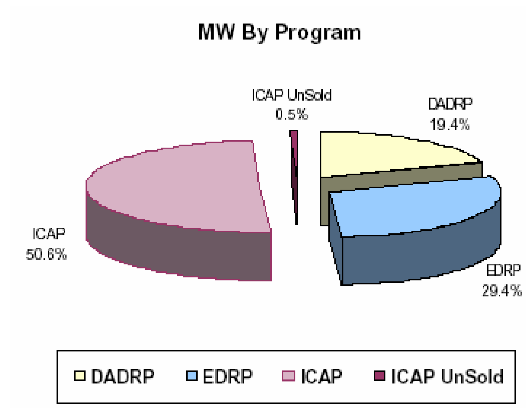


Figure 2-2 Enrolled MW by Program

Table 2-1, Program Participation Summary by Curtailment Service Provider (CSP) Type, shows program participation by Curtailment Service Provider (CSP) type. Customers enroll in NYSIO demand response programs through one of five means; through an Aggregator, a Load Serving Entity (LSE), and Transmission Owner (TO), or as a Direct Serve customers or a Curtailment Program End-Use Customer (CP-EUC). They are defined as follows:

[7] A participant is defined as a single customer enrolled in a program individually or as part of an aggregated resource.

[8] Resources in the ICAP program with unsold capacity are considered as EDRP resources in the month(s) that capacity is not sold.

- Aggregators are entities that recruit customers to participate as part of an aggregation of several customers.
- LSEs are competitive providers of commodity service to retail customers.
- TOs are the state's seven utilities.
- A Direct Customer is a retail customer that has registered as a member of the NYISO and consequently can participate directly in its markets.
- Curtailment Program End-Use Customer is a customer that enrolls directly with the NYISO in the EDRP program, the only program that allows such an arrangement.

		EDRP [1]		ICAP UnSold [2]		ICAP [3]		DADRP [4]	
CSP Type #	CSP Type	#	MW	#	MW	#	MW	#	MW
15	Aggregator	58	20.5	14	2.2	722	512.0	0	0.0
0	Curtailment Program End-Use Customer	0	0.0	0	0.0	0	0.0	0	0.0
2	Direct Customer	0	0.0	0	0.0	1	2.0	1	8.0
9	LSE	13	8.1	15	8.1	178	309.9	4	46.5
8	Transmission Owner	1026	542.1	0	0.0	32	156.9	12	322.4
34	**Total**	**1097**	**570.7**	**29**	**10.3**	**933**	**980.8**	**17**	**376.9**

Note 1: The sum of EDRP and ICAP UnSold = Total EDRP.
Note 2: Participants in the ICAP program with UnSold capacity are considered as EDRP resources in the month(s) that capacity is unsold. MW represent reductions registered in the ICAP program, but not sold.
Note 3: MW represent reduction MW sold in the ICAP program.
Note 4: Total NYISO participation is not necessarily the sum of all programs due to the rules that state that participants are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP).

Table 2-1 Program Participation Summary by Curtailment Service Provider (CSP) Type

Figure 2-4, Figure 2-3, Figure 2-6, and Figure 2-5 show the relative contributions to each program by CSP type. Aggregators provide only about 5% of participants and load to EDRP, which is dominated in both categories (over 94%) by enrollments through TOs. Conversely, ICAP-SCR enrollments are dominated by Aggregators, which provide 66% of participating customers and 90% of the load. LSEs are virtually inactive in the EDRP market but provide 19% of participants and 32% of load to ICAP-SCR. In 2004, there were no Direct Customers or Curtailment End-Use Customers enrolled in EDRP and only one Direct Customer enrolled in ICAP-SCR.

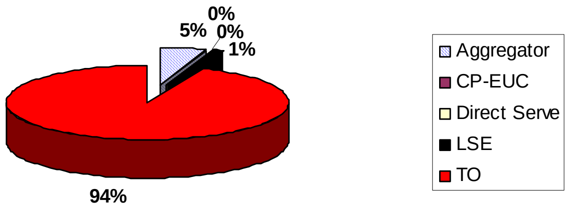


Figure 2-4 EDRP Participants (number) by Curtailment Service Provider (CSP) Type

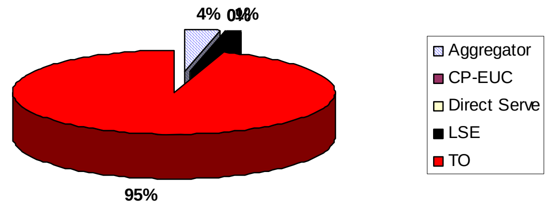


Figure 2-3 EDRP Load (MW) by CSP Type

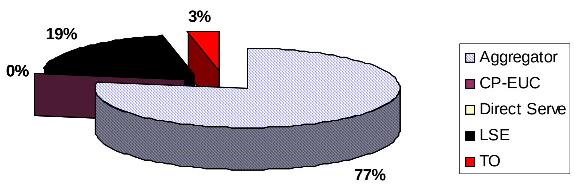


Figure 2-6 Sold ICAP-SCR Participants (number) CSP Type

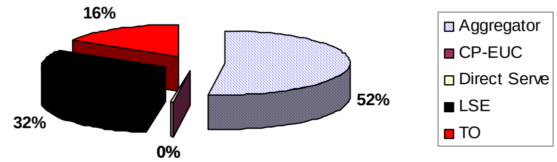


Figure 2-5 Sold ICAP-SCR Load (MW) by CSP Type

Table 2-2, 2004 Program Participation by Zone, shows program participation detail by NYISO zone. Zones J and K, New York City and Long Island, respectively, have the majority (68%) of participants in the EDRP program which represent 53% of the total MW enrolled. For the ICAP-SCR program, Zones J and K constitute an even greater percentage (72%) of statewide participation, but account for only 28% of the total enrolled MW. The Western superzone, made up of zones A through E, is characterize by greater load per participant, providing 21% of participants in EDRP and 29% of total enrolled MW and 25% of the participants in ICAP-SCR which provide 64% of total program MW.

	EDRP (1)		ICAP UnSold (2)		ICAP (3)		DADRP (4)	
Zone	#	MW	#	MW	#	MW	#	MW
A	45	39.4	0	0.0	128	357.6	3	126.0
B	17	36.6	0	0.0	27	52.3	0	0.0
C	101	32.1	0	0.0	43	102.6	2	37.4
D	14	5.1	0	0.0	5	84.7	1	100.0
E	50	50.8	0	0.0	26	32.6	1	10.0
F	54	45.0	0	0.0	20	64.0	8	89.0
G	35	45.4	0	0.0	2	1.4	0	0.0
H	9	6.5	1	0.2	4	4.0	0	0.0
I	24	9.6	11	2.6	5	9.1	0	0.0
J	138	146.4	15	7.0	637	174.7	1	2.5
K	610	153.8	2	0.5	36	97.8	1	12.0
Total	**1097**	**570.7**	**29**	**10.3**	**933**	**980.8**	**17**	**376.9**

Note 1: The sum of EDRP and ICAP UnSold = Total EDRP.

Note 2: Participants in the ICAP program with UnSold capacity are considered as EDRP resources in the month(s) that capacity is unsold. MW represent reductions registered in the ICAP program, but not sold.

Note 3: MW represent reduction MW sold in the ICAP program.

Note 4: Total NYISO participation is not necessarily the sum of all programs due to the rules that state that participants are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP).

Table 2-2 2004 Program Participation by Zone

Count and Subscribed MW by Curtailment Method

Table 2-3, 2004 Program MW by Curtailment Type and Zone, shows the number of participants in each zone and the amount of load reduction and generation subscribed under each program. Participants in EDRP subscribed 57% of the program's total curtailable MW as load reduction and the remainder (43%) through generation resources. The ICAP-SCR program had the majority of curtailable MW coming from load reductions with 90% of the curtailable MW and the remainder from generation. DADRP does not permit the use of on-site generation to be pledged into the program, thus all 376.9 MW subscribed come from load reduction.

	EDRP (1)			ICAP UnSold (2)			ICAP (3)			DADRP (4)		
Zone	#	Load	Gen	#	Load	Gen	#	Load	Gen	#	Load	Gen
A	45	25.0	14.4	0	0.0	0.0	128	357.1	0.5	3	126.0	0.0
B	17	20.1	16.5	0	0.0	0.0	27	45.8	6.5	0	0.0	0.0
C	101	15.2	16.9	0	0.0	0.0	43	100.0	3.6	2	37.4	0.0
D	14	1.7	3.4	0	0.0	0.0	5	84.7	0.0	1	100.0	0.0
E	50	23.3	27.5	0	0.0	0.0	26	30.8	0.8	1	10.0	0.0
F	54	35.8	9.2	0	0.0	0.0	20	64.0	0.0	8	89.0	0.0
G	35	21.0	24.5	0	0.0	0.0	2	1.4	0.0	0	0.0	0.0
H	9	1.2	5.3	1	0.1	0.0	4	2.2	0.0	0	0.0	0.0
I	24	5.0	4.6	11	2.4	0.0	5	10.7	0.2	0	0.0	0.0
J	138	90.9	55.6	15	2.2	0.4	637	167.8	6.9	1	2.5	0.0
K	610	84.1	69.8	2	0.1	0.1	36	19.9	77.9	1	12.0	0.0
Total	**1097**	**323.1**	**247.6**	**29**	**4.8**	**0.5**	**933**	**884.4**	**96.4**	**17**	**376.9**	**0.0**

Table 2-3 2004 Program MW by Curtailment Type and Zone

Migration Summary

Table 2-4, Program Enrollment Changes, 2003 to 2004, provides a summary of how enrollment changed from 2003 to 2004 and the average subscribed MW per participant for each year. Overall, participation and the number of MW enrollment decreased in the EDRP and DADRP programs. However, 2004 ICAP-SCR program participation increased by 44% over 2003, proportionally greater than the 30% increase in subscribed MW. Note that the comparison of ICAP-SCR between 2004 and 2003 is on the basis of resources, which masks the number of customers involved in aggregations, as discussed earlier. All but the DADRP program were characterized by a decline (10-19%) in the average subscribed MW per participant. The average MW per participant in ICAP-SCR is seven times that of EDRP in 2004.

	2003		2004		Percent Change From 2003 to 2004		Subscribed MW per Participant		
	Count	MW	Count	MW	Participant Count	Subscribed MW	2003	2004	Percent Change
EDRP	1342	864.6	1097	570.7	-18%	-34%	0.64	0.52	-19%
ICAP UnSold	25	73.9	15	5.3	-40%	-93%	2.96	0.35	-88%
ICAP	186	756.0	268	980.8	44%	30%	4.06	3.66	-10%
DADRP	25	470.3	17	376.9	-32%	-20%	18.81	22.17	18%

Table 2-4 Program Enrollment Changes, 2003 to 2004

An important measure of program performance is retention and migration. Retention is defined as a customer remaining in a program two consecutive years, including the current reporting year. Migration is defined by a customer changing from the program it participated in the previous year to a new NYSIO program in the reporting year.

Figure 2-7, Demand Response Program Migration - Resources, provides a detailed accounting of changes in program participation in terms of migration and retention, from 2003 to 2004. The rows in Figure 2.3 correspond to the four programs. The last row of the figure shows how the previous year's participation (for each program) is adjusted for retention (drop outs and new additions) and migration (from another program) to produce the current year's program participation, which matches the values in Table 2-1.

	Previous Year*	Drop (5)	New (6)	Net Migration (7): EDRP	Net Migration (7): ICAP UnSold	Net Migration (7): ICAP	Net Migration (7): DADRP	Current Year**	Percent Change Previous Year to Current Year
EDRP (1)	1,342	348	116		0	-10	-3	1,097	-18%
ICAP UnSold (2)	25	21	10	0		2	-1	15	-40%
ICAP (3)	186	83	156	10	-2		1	268	44%
DADRP (4)	25	4	2	-4	0	-2		17	-32%
Calculation	Previous Year*	- Drop	+ New	+ Net Migration				= Current Year**	

Note 1: The sum of EDRP and ICAP UnSold = Total EDRP.
Note 2: Participants in the ICAP program with UnSold capacity are considered as EDRP resources in the month(s) that capacity is unsold. MW represent offered unsold MW.
Note 3: MW represent reduction MW sold in the ICAP program.
Note 4: Total NYISO participation is not necessarily the sum of all programs due to the rules that state that participants are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP).
Note 5: Drop is defined as a participant who was enrolled in a NYISO DR program in the previous year and choose not to enroll in either an alternative NYISO DR program or in the same NYISO DR program in the current year.
Note 6: New is defined as a participant who enrolls in a NYISO DR program in the current year and was not enrolled in any NYISO DR programs in the previous year.
Note 7: Net Migration is the net amount of participants/MWs out of and into a NYSIO DR Program. (e.g. 20 participants move into EDRP from another NYISO DR program at the same time that 10 participants move out of EDRP into another NYISO DR program so, Net Migration = 20 – 10 = +10)

Figure 2-7 Demand Response Program Migration - Resources

For example, consider the EDRP program, the first row in Figure 2-7. Beginning with the enrollment for 2003 (1,342) shown in the first column, labeled Previous Year. The next two columns show the number of resources that withdrew from EDRP in 2004 (Drop) and the number that joined EDRP for the first time (New) in 2004, respectively. The next set of columns track net migration (net change in resources) from EDRP to other NYISO DR programs.

Each box in the Net Migration section of Figure 2-7 represents the net inflow from another program and outflows of participants to a different NYISO DR program. Tracking migration is important given that each program has different provisions and it is thought that experiences in programs with simpler requirements act as a training ground for participation in programs that have penalties for non-compliance. In Figure 2-7, the Net Migration section serves to illustrate the net change in resources so that enrollment can be tracked from one year to the next, but it does not show where participants came from when joining a given program or where participants went when they left the program they were in during the previous year.

To understand this level of change within a given program, refer to Figure 2-8, Migration Detail, which expands the Net Migration section of Figure 2-7 to show detailed movement into and out of each Demand Response program. Continuing with the EDRP program example, the first row of Figure 2-7, shows that no customers (0) switched from the ICAP-SCR not sold category in 2003 to EDRP in 2004, that a net change of 10 customers that were in EDRP in 2003 left for ICAP-SCR in 2004 (thus the –10 entry), and a net change of three (-3 entry) left for DADRP. For EDRP, the Net Migration Detail shown in Figure 2-8 shows this clearly.

	In From EDRP	Out to EDRP	In From ICAP UnSold	Out to ICAP UnSold	In From ICAP	Out to ICAP	In From DADRP	Out to DADRP
EDRP (1)			0	0	0	-10	0	-3
ICAP UnSold (2)	0	0			5	-3	0	-1
ICAP (3)	10	0	3	-5			1	0
DADRP (4)	2	-6	0	0	0	-2		

Figure 2-8 Migration Detail

To further illustrate the difference between the Net Migration in Figure 2-7 and the Migration Detail provided in Figure 2-8, consider the fourth row of Figure 2-7, the DADRP program. Here Figure 2-7 shows a Net Migration of –4, indicating a net transfer of DADRP participants to EDRP. In Figure 2-8, the DADRP row shows the detail of changes to the DADRP program with respect to EDRP participants: two participants from EDRP transferred to DADRP and six participants left DADRP for EDRP resulting in the net change of –4 (2-6) shown in the Net Migration table in Figure 2-7. The second to the last column in Figure 2-7 shows the total enrollment in EDRP for 2004, and the last column displays the percent change in enrollment from the Previous Year, 2003.

Overall, EDRP participation when down 18%, largely due to customers that apparently dropped out of the NYISO demand response programs completely, and ICAP participation increased. It is possible that some or perhaps most of these customers transferred to the ICAP-SCR program, but that migration is masked by the fact that the table involves a comparison of resources, and not actual customers.

Figure 2-9, Demand Response Program Migration – Subscribed MW, provides the same detailed accounting of changes in program subscription, but for the level of MW offered or committed for curtailment instead of participation. One additional column is included in Figure 2-9 to account for changes to the level of subscribed MW made by re-enrolling participants. Some of the net change in program MW between 2003 and 2004 is due to customers that reenroll in the same program but increase or decrease the level of MW subscribed to that program. It is important to distinguish between changes due to migration and those due to change in the level of curtailment committed by customers that continue their participation from year to year.

	Previous Year*	Drop[5]	New[6]	Net Migration[7] EDRP	ICAP UnSold	ICAP	DADRP	Changes to Subscribed MW[8]	Current Year**	Percent Change Previous Year to Current Year
EDRP[1]	864.6	253.7	39.6		0.0	-13.7	-80.5	14.3	570.7	-34%
ICAP UnSold[2]	73.9	18.0	3.5	0.0		-10.9	-43.2	0.0	5.3	-93%
ICAP[3]	756.0	389.8	538.5	37.7	10.7		8.2	19.5	980.8	30%
DADRP[4]	470.3	142.5	24.5	70.6	0.0	-51.0		5.0	376.9	-20%
Calculation	Previous Year*	- Drop	+ New	+ Net Migration				+ Changes to Sub. MW	= Current Year**	

Note 1: The sum of EDRP and ICAP UnSold = Total EDRP.

Note 2: Participants in the ICAP program with UnSold capacity are considered as EDRP resources in the month(s) that capacity is unsold. MW represent offered unsold MW.

Note 3: MW represent reduction MW sold in the ICAP program.

Note 4: Total NYISO participation is not necessarily the sum of all programs due to the rules that state that participants are allowed to participate in a reliability program (EDRP or ICAP) and economic (DADRP).

Note 5: Drop is defined as a participant who was enrolled in a NYISO DR program in the previous year and choose not to enroll in either an alternative NYISO DR program or in the same NYISO DR program in the current year.

Note 6: New is defined as a participant who enrolls in a NYISO DR program in the current year and was not enrolled in any NYISO DR programs in the previous year.

Note 7: Net Migration is the net amount of participants/MWs out of and into a NYSIO DR Program. (e.g. 20 participants move into EDRP from another NYISO DR program at the same time that 10 participants move out of EDRP into another NYISO DR program so, Net Migration = 20 – 10 = +10)

Figure 2-9 Demand Response Program Migration – Subscribed MW

Curtailment Bids in ICAP-SCR

Beginning in 2003, participants in the ICAP-SCR program were required upon enrollment to indicate a curtailment strike price, between 0-$500/MWH, which would be used by the NYISO to determine which resources to call for curtailments in the case where all available resources were not needed to restore system security to its equilibrium state. The NYISO anticipated stacking the curtailment strike prices in accenting order, in the same way it stacks generation supply bids, specifying the MW of curtailment needed, and calling all the resources that bid a strike price at or below the resulting price. A linear dispersion of strike prices over the MW/Price space would provide the NYISO with the greatest granularity for dispatching ICAP-SCR resources. If bids are clumped together too tightly, then some of the flexibility is lost.

To characterize how participants responded to this requirement, strike price curves were developed for all resources for 2004, and then the strike prices were disaggregated to characterize the nature of bids according to how long participants had been enrolled in the ICAP-SCR program. The curves map out the percentage of MW at a given strike price. If the program strike price curve is a straight line out of the origin and intersects the $500 price ceiling at the 100% load level, then the dispersion of resources for dispatch purposes would be uniform, providing the ISO utmost flexibility is dispatching only as many resources as are needed. If that line was bowed upward, then resources are clumped at lower prices, and if it is bowed downward, the bias it toward higher prices. If the curve intersects the $500 threshold price at a load level under 100%, then resources are clumped even more dramatically toward the highest price, and the bid curve offers little dispersion and therefore limited dispatch flexibility.

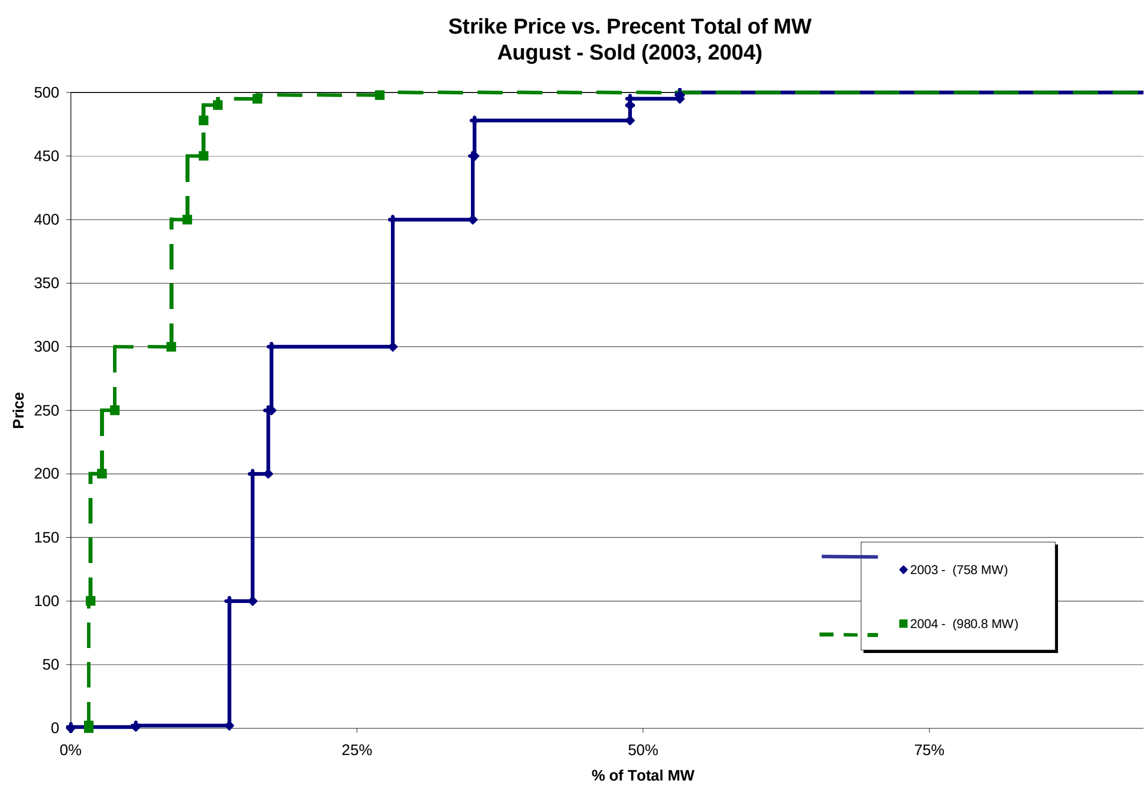


Figure 2-10 2003 and 2004 ICAP-SCR Curtailment Bid Curves

Figure 2-10, 2003 and 2004 ICAP-SCR Curtailment Bid Curves, illustrates the strike price curves for 2003 to 2004, the two years the provision has been in place. First, both strike price curves intersect the $500 threshold at 50% load or less, indicating that bids are highly clumped around the threshold. Second, the 2004 curve shows an even greater concentration of strike prices at the $500 threshold than that of 2003.

The steeper slope for the strike price curve overall indicates that strike prices are clustered close to the bid ceiling of $500/MWH. Higher strike prices in 2004 may be the result of the outcome of the 2003 blackout. Each participant that is called upon to curtail during an ICAP-SCR event and responds, under program provisions, is paid the market price at the time of the event, plus an additional amount defined by the difference its strike price and the market price at the time of the event. Generally, these circumstances would result in market prices being close to the strike prices of the last ICAP-SCR resource dispatched, so the make-up payments would be small. However, in 2003, the day after the 2003 blackout, an ICAP-SCR event was declared and all ICAP-SCR resources called upon to curtail. But real-time market prices were set administratively at around $125/MWH. Thus, the strike price had no impact on which participants were called upon to curtail, but those with a strike price below were paid only $125/MWH, and those above received the market prices, plus a makeup bid that resulted in their being paid a higher price. Given this experience, it is not surprising that this year's strike prices are predominantly high.

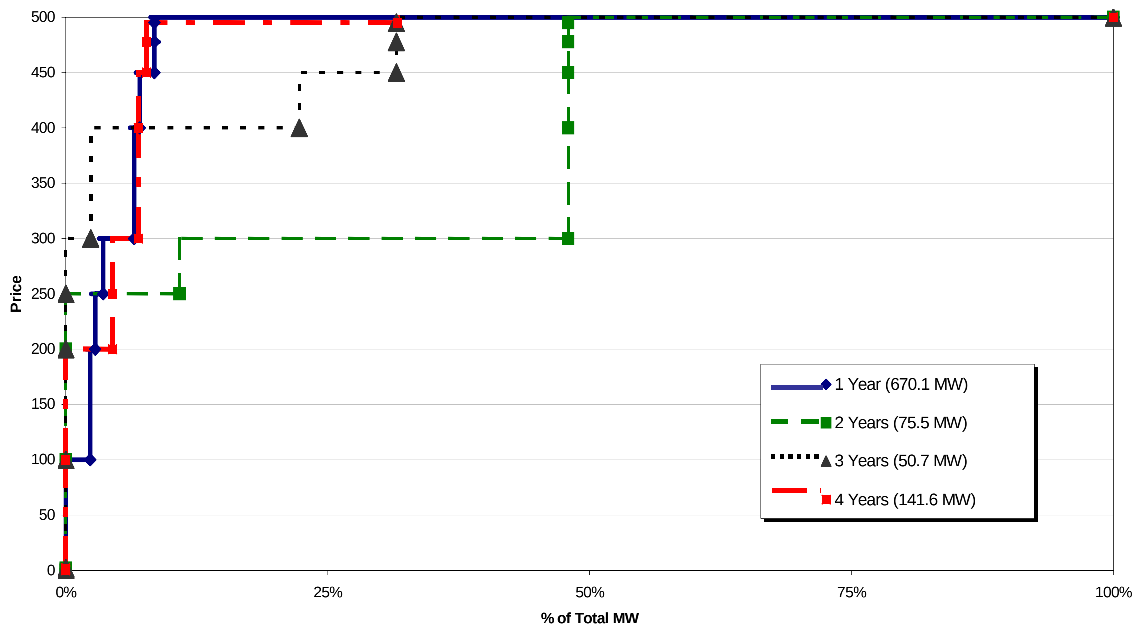


Figure 2-11 2004 ICAP-SCR Curtailment Bid Curves by Years of Experience in ICAP-SCR

Figure 2-11, 2004 ICAP-SCR Curtailment Bid Curves by Years of Experience in ICAP-SCR, illustrates the 2004 strike price curve separately to reflect the number of years' experience with program participation; one, two, three, or four years.[9] The strike price curve for customers with one (which represent 624 MW, 64% of total load in ICAP-SCR and four years of experience (245 MW, 25% of total load in ICAP-SCR) show little dispersion, characterized by a few strike prices at around $250/MW, and the rest at or near $500/MW. Customers with two years of experience exhibit the greatest strike price dispersion, but they represent only about 7% of total enrolled load.

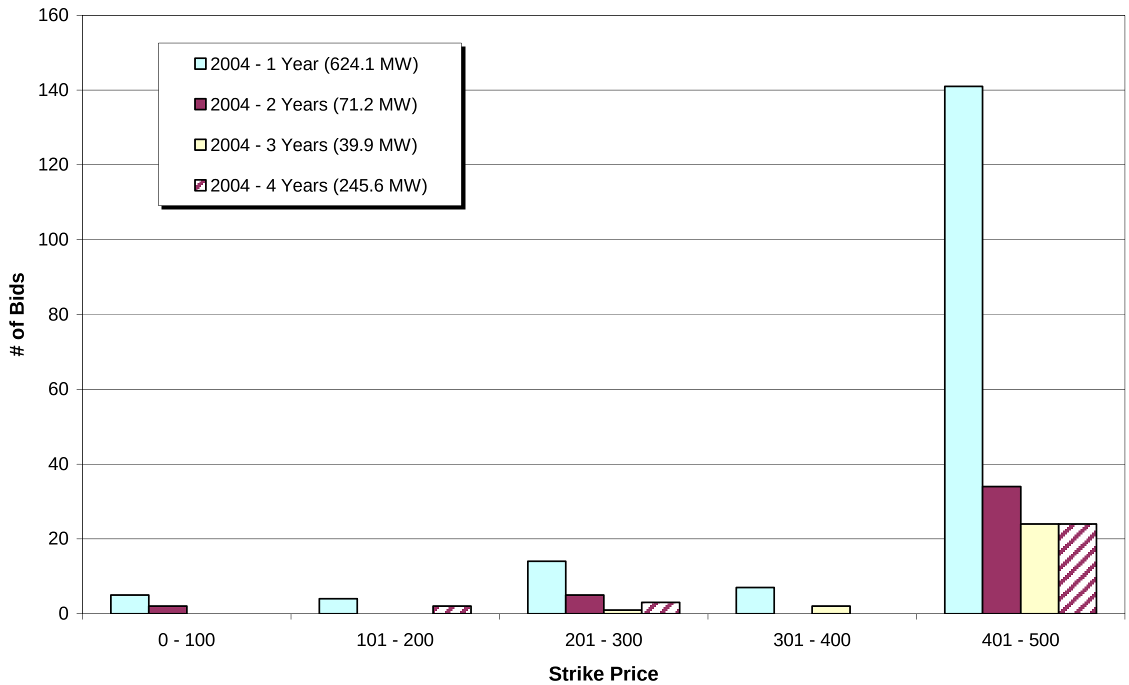


Figure 2-12 Number of ICAP-SCR 2004 Curtailment Bids at various levels of experience in ICAP-SCR

Figure 2-12, illustrates the same concept, but plots the frequency of the strike prices for five different price levels, which divide the price range into five equal increments. It illustrates that the large influx of new customers in 2004 predominantly chose strike prices equal to the ceiling price, and most of the others chose a strike price at least $250. However, the same is true for program veterans, they predominantly chose the $500/MWH ceiling price. Figure 2-13 provides the same perspective, but for the 2003 distribution of strike prices, and reinforces the strong trend toward bids by new entrants at the bid threshold.

[9] ICAP-SCR registration records are kept beginning in 2001, but the program began in 2000 with a small level of participation.

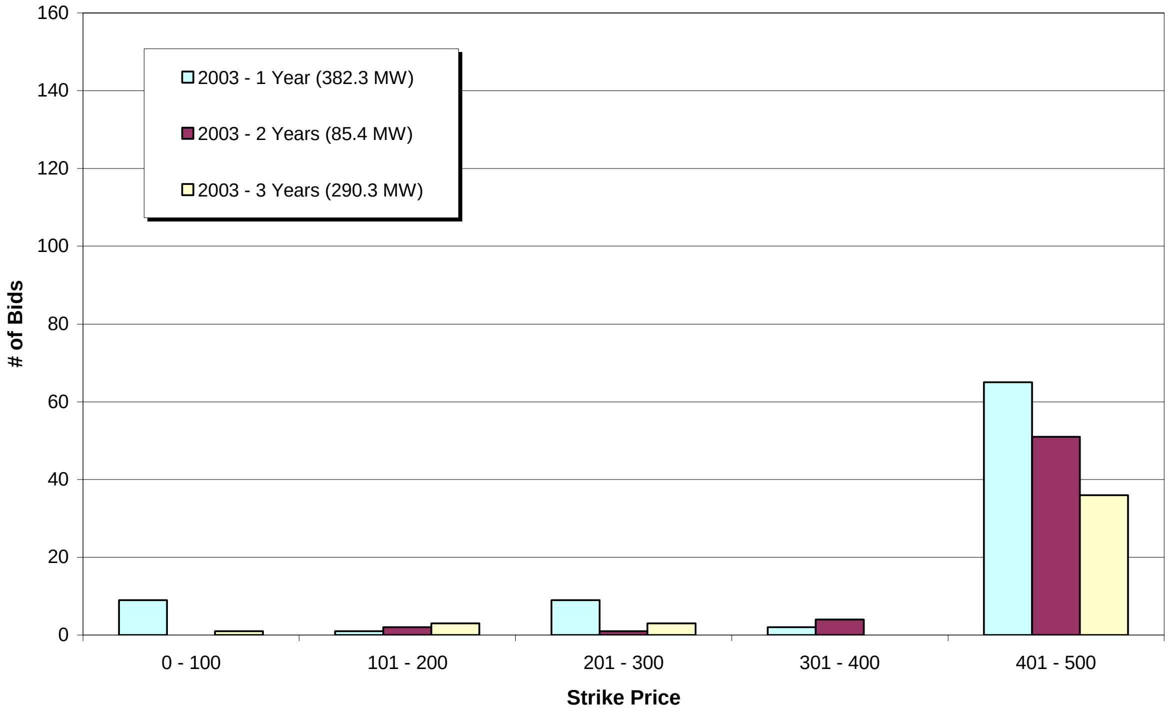


Figure 2-13 Number of ICAP-SCR 2003 Curtailment Bids at various levels of experience in ICAP-SCR

The objective of the ICAP-SCR bid curve was to make the collective resources more divisible, so that they could be dispatched more efficiently and effectively. However, it has not been very successful, as strike prices are predominantly at the threshold prices of $500/MWH. If not all of the resources are needed, then dispatchers facing the choice of too little of too much are likely to err on the side to too much, which can have undesirable impacts on real-time energy market prices.

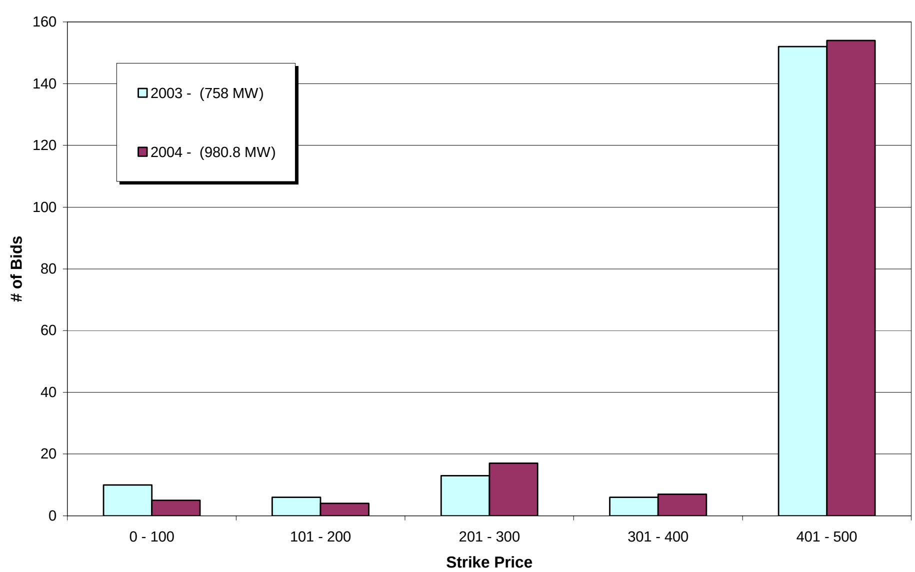


Figure 2-14 Number of ICAP-SCR Bids by Strike Price - August 2003 and August 2004

DADRP Bidding Summary

Overall, fewer DADRP bids were scheduled in 2004, largely due to the lower price volatility of the DAM. DADRP bids were scheduled a total of 1,275 hours during this reporting period, September 1, 2003 and August 31, 2004, which resulted in 3,535 MWHs of load reductions, and average hourly reduction of 2.77 MW. Figure 2-15 shows a comparison of scheduled DADRP bids by season since the program's inception. A pattern has emerged over the past 3 year. Few bids are scheduled in the spring and fall, when DAM prices are relatively low, and a greater number of bids are scheduled in the summer and winter, when DAM prices are higher. In addition, the imposition of the $50/MWH price floor in 2002 has reduced overall the number of bids that are scheduled. Due in large part to the low prices experienced during the summer of 2004, even fewer bids were scheduled this year compared with the summers of 2003 and 2002. However, the number of bids scheduled during the winter of 2004 is comparable to that of past years.

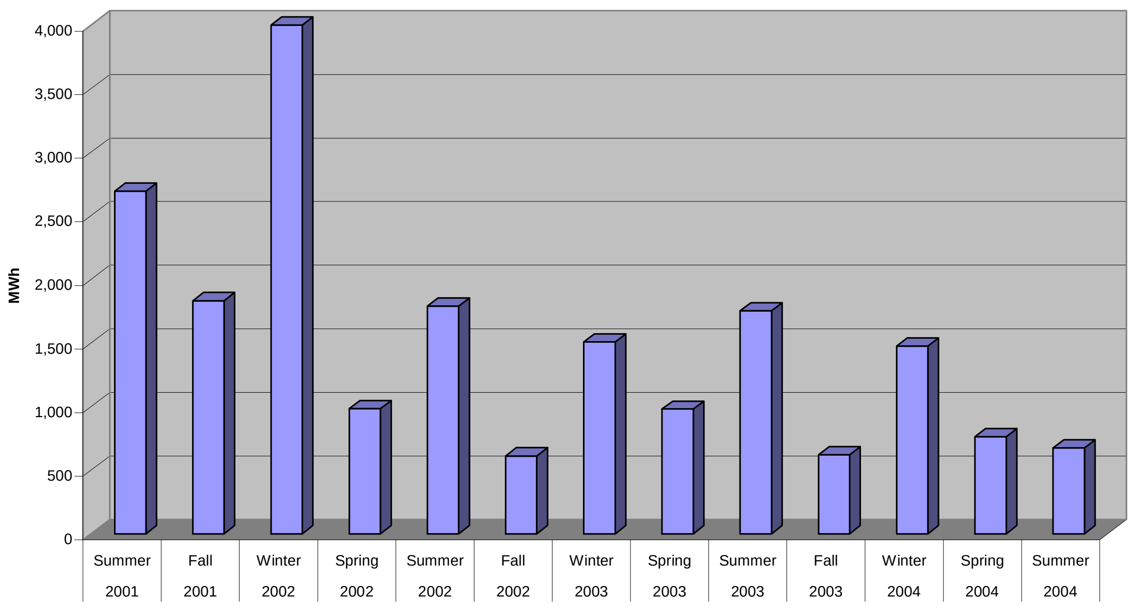


Figure 2-15 Total Scheduled DADRP Bids (MWh) by Season and Year

The average size of scheduled bids is declining. The average scheduled hourly bid between September 1, 2003 and August 31, 2004 was 2.7 MW, which is lower than the previous year (2.9 MW) and substantially less than the same period in 2001-2002 (4.8 MW). Figure 2-16 shows the average accepted hourly bid by season since the program began.

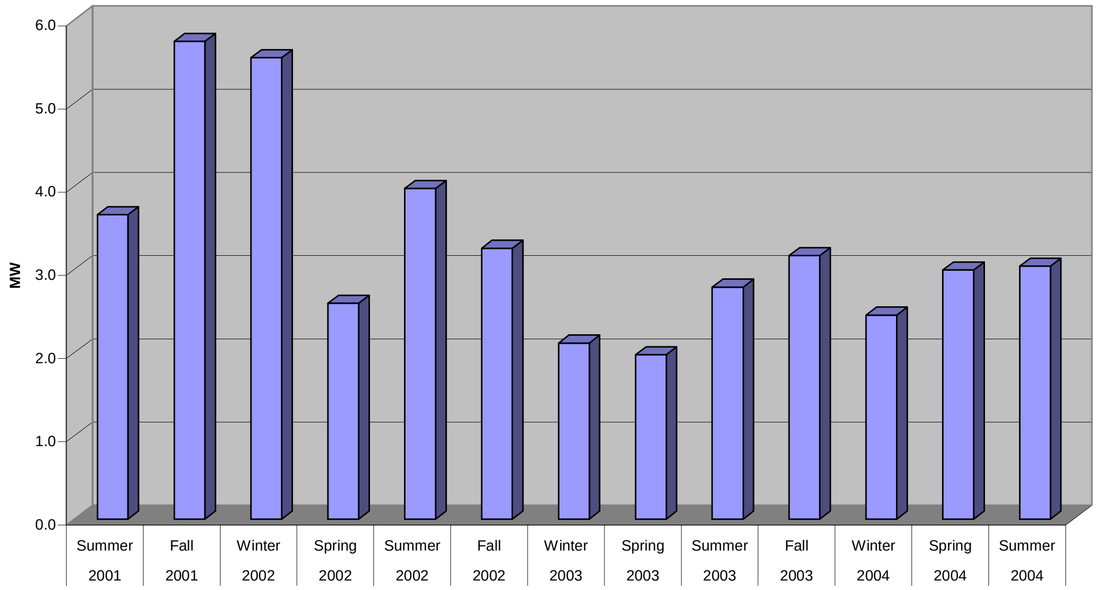


Figure 2-16 Average Scheduled Hourly DADRP Bids (MWh) by Season and Year

DADRP bids in 2004 were largely scheduled during the day and evening hours, 9:00 a.m. to 10:00 p.m. Figure 2-17 shows the number of scheduled MWHs of load curtailment by hour and program year (September 1 – August 31) for 2002-2004. The imposition of the $50/MWH bid floor is largely responsible for the reduction in the number of overnight bids scheduled in the past two years, compared to the first year, along with the general reduction in price volatility.

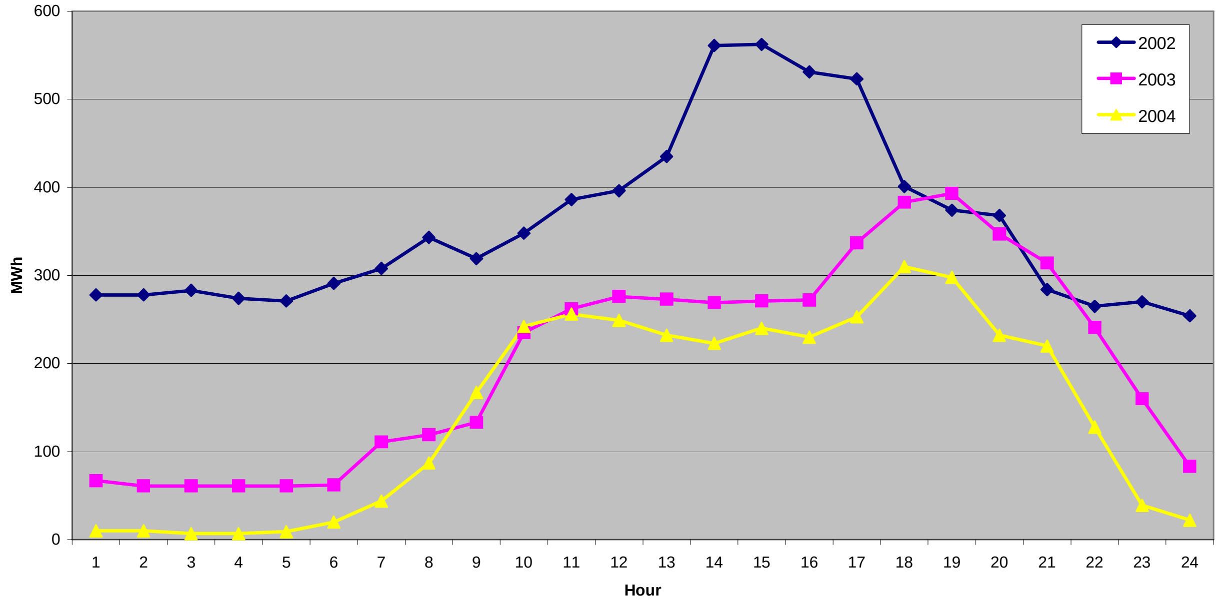


Figure 2-17 Total Scheduled DADRP Bids (MWh) By Hour and Program Year (9/1 - 8/31)

3 Event Summary

System Conditions resulting in declaration of events

No reliability events were called during the summer of 2004.

Performance Summary

Not applicable

RT Market Prices during events

Not applicable

4 Estimated Benefits Summary

Estimated Benefits Summary

Scheduled DADRP curtailments impact the NYISO market in three distinct ways. First, when DADRP curtailments displace higher priced generation resources, the corresponding DAM clearing price drops, thereby reducing the cost of purchases made by LSEs through fixed price and price cap load bids. The amount of those bill savings depends on how steep the supply curve was at that time. The steeper the supply curve, the larger the reduction in prices when demand is reduced. Such reductions in DAM LBMPs will also cause the expected future market outlook of price volatility to be reduced. These expectations are hypothesized to place downward pressure on bilateral transactions between LSEs and suppliers. Hedge cost savings and bill savings are both transfer payments. Money that formerly was paid by LSEs, on their retail customers' behalf, to generators is now in effected transferred back to LSEs, and eventually to their customers, as avoided costs.

From a social welfare perspective, as defined by economists, these transfers are not defined as benefits, just neutral transfers among market participants with no specific weight or merit. However, such transfers are important to consumers, since they amount to reduced costs for the electricity purchased by consumers, and all other things equal, they are therefore desirable.[10] Economists define a third flow of benefits that results when customers respond to actual market costs rather than usage prices based on average costs. Such changes in usage of electricity reduce deadweight social losses, which are defined as the utilization of resources in other than the socially optimal manner. DADRP induces customers paying average prices for electricity to adjust their usage to contemporary, actual supply costs, thereby reducing deadweight losses and improving social welfare. This third flow of benefits from DADRP is the improvement in net social welfare that is realized when DADRP bids from participants on flat-rate tariffs are scheduled.

[10] Some (Ruff 2002) have argued that such transfers are in fact undesirable from a pan-market perspective, as the lower prices lower expectations for returns to investments in generation, lower capacity investments, and subsequently elevate market prices. However, this line of reasoning misses the fact that lowering price volatility actually serves to reduce investors' expectations for the variance of returns in generations, and lower variance in returns generally is considered to increase the level of investment, all other things being equal.

Market price impacts for the summer months (June, July and August) of 2004 were estimated using the methods and protocols developed previously.[11] Supply flexibilities were developed for two aggregate regions: Western NY and Hudson River, and two NYISO zones: New York City and Long Island.[12] Supply flexibilities, defined as the percentage change in LBMP resulting from a one percent change in the load served, characterize the nature (slope) of the resource supply curve. The greater the price flexibility, the greater the reduction in the calculated DAM LBMP due to the scheduling of a DADRP curtailment bid. High supply flexibilities over a narrow range of load levels are indicative of a pronounced "hockey-stick" shaped supply curve. In the market impact analyses, the supply flexibilities are used to construct a statistical representation of the bid curve during hours that DADP bids are scheduled, so that the level of price that would have been achieved in the DAM and RTM, had these curtailments not been scheduled and delivered, can be estimated, as well as the corresponding bill savings. In addition, the supply flexibility is used in the derivation of the net social welfare results.

Overall, price flexibilities in the 2004 DAM are comparable to those reported in 2003, while the RTM experienced much lower flexibilities than last year, as illustrated in Table 4-1 and Table 4-2. However, the estimated price flexibilities in both markets still remain much lower than they were in either of the first two years of the demand response programs. The low price flexibilities result in smaller market effects when DADRP curtailment bids are scheduled, and as demonstrated below, undermine the net social welfare gains from DADRP.

	2001	2002	2003	2004
West	6.4	6.7	3.4	2.3
Hudson/Capital	8.6 / 8.4	4.7 / 6.0	2.5	1.2
New York City	14.5	12.8	5.9	1.8
Long Island	10.4	5.2	6.0	2.1

Price Flexibility = % change in LBMP resulting from a 1% change in load served

Table 4-1 DAM Price Flexibilities (Summer)

[11] This analysis is confined to the summer months to accommodate a comparison of 2004 results with prior year's analyses that included only these months. More detailed impacts of DADRP for September 2003 – May 2004 are provided in an appendix.

[12] Western NY superzone consists of NYISO zones A – E, while the Hudson River superzone is comprised of NYISO zones F – I.

	2001	2002	2003	2004
West	9.4	4.2	1.4	1.8
Hudson/Capital	5.1 / 11.8	3.9 / 5.0	1.9	1.6
New York City	9.4	3.6	3.5	0.7
Long Island	5.1	6.5	1.2	0.6

Price Flexibility = % change in LBMP resulting from a 1% change in load served

Table 4-2 RTM Flexibilities (Summer)

All three types of market effects estimated for the summer of 2004 are compared to those from 2001 through 2003 in Table 4-3.[13] The lower level of scheduled DADRP bids in 2004 resulted in a 78% reduction collateral savings and reduced hedge costs (Table 4.3). Collateral impacts measure the reduction in the cost of DAM and RTM purchases by LSEs resulting from DADRP scheduled curtailments depressing prices. Hedge cost impacts estimate the ripple effect lower prices in the DAM during curtailment hours are postulated to have on future bilateral contract supply costs.

	Scheduled DADRP MWHs	Collateral Savings	Reduction in Hedge Cost	Total Market Effect	Program Payments	Change in NSW
2001	2,694	$892,140	$682,358	$1,574,498	$217,487	N/A
2002	1,468	$236,745	$202,349	$439,094	$110,216	N/A
2003	1,752	$45,773	$161,558	$207,331	$121,144	-$72,271
2004	675	$8,996	$36,940	$45,936	$40,651	-$27,408

Table 4-3 DADRP Market Effects (Summer)

DADRP scheduled bids resulted in a decrease in net social welfare (NSW), although the amount ($27,408) is less than in 2003. The change in NSW reflects a change in allocative efficiency of scarce resources due to customers on a flat rate being able to express their changing value for electricity through load-curtailment bidding. The DADRP program is intended to provide improvements in NSW. Why then are NSW benefits negative the past two years? The answer is that scheduling DADRP bids at relatively low DAM prices, for example at the $50/MWH bid floor price, generally corresponds to a very low supply flexibility, the supply curve is relatively flat, and the deviance from the average price the

[13] In previous years, market impacts were estimated only for the summer months, where DADRP bids were most likely to be scheduled. Starting in 2004, market impacts are estimated for the entire year. In order to accommodate year-to-year comparisons, the summer 2004 impacts are presented here. The appendix provides the full year's results.

customer pays and the socially optimum DAM price is very small. The change in NSW is based on that deviation, net of the payment the customer receives for curtailing, i.e., the DAM price. When the supply curve is very flat, the reduced deadweight loss can be less than the payment to the customers, i.e., the DAM price, resulting in a reduction in NSW.

Do negative NSW contributions mean that DADRP is counterproductive? Can changes be made in the program that would reduce or eliminate negative NSW results? DADRP is intended to reduce price volatility. When prices are very high, $500/MWH or more, as they were at times in 2000-2002, the incentives to shift load for DADRP participants are high. Moreover, these circumstances are coincident with very high supply flexibilities, upwards of 10 at times in 2001-2002, which result in relatively greater reductions in deadweight losses from DADRP induced curtailments, and positive NSW contributions. The challenge is how to induce customers to join the program and monitor prices so that when they spike, DADRP bids will be forthcoming, scheduled, and deliver NSW improvements, and provide them with opportunities to realize benefits when prices are low, and their curtailment costs are even lower.

The current market situation is that prices are very low. Some DADRP participants appear to be trying to make the best of the situation by entering relatively low bids, at or near the floor price, when they find that they can curtail at an even lower cost. If these benefits are taken away, will these customers lose interest in DADRP altogether, leave the program, and effectively eliminate this important restraint on price volatility? With only limited experience, there is no way to answer this question. However, the level of the NSW losses are negligible, especially if they are a necessary payment to ensure that there are DADRP bidders around when prices soar, and scheduled curtailment bids produce large positive NSW benefits.

Changes to DADRP provisions would reduce the incidence of negative NSW results. The simplest means is to raise the bid floor to a level that reduces, or even eliminates the incidence of negative changes in NSW. However, setting that floor at a fixed level may resulting rejecting DADRP bids when, due to market circumstances, they would be welfare improving. Moreover, some argue that raising the floor much above $50/MWh would so limit the potential benefits that participation would be drastically reduced, to a level that would be ineffective at abating price spikes. The NYISO is considering ways to reduce the potential for negative NSW results from DADRP, without making participation so unattractive that the program is unattractive to customers.

The lower market effects in 2004 reflect the relatively flat nature of the resources supply curve during the summer months. Low supply flexibilities mean that scheduled curtailments have a lower impact on the DAM LBMP. Program costs are based on the price at which the DADRP curtailment was scheduled, but are also down substantially from 2003. The ratio of market effects, the sum of transfer costs and NSW, to DADRP curtailment payments, referred to as the program impact ratio, in 2004 was 1.1, compared to 1.7, 4.0 and 7.2 in 2003, 2002, and 2001 respectively. In general, the low impact ratio in 2004 is attributable to the low DAM prices and low supply flexibilities.

5 Appendices

Appendix A - Market Trends

The NYISO's Day-Ahead market experienced a relatively flat year in 2004 where prices did not reach significantly high levels nor did they increase on average. As shown in Figure 5-1, the average price in program year 2004 was slightly less than that observed in program year 2003.[14] In fact, aside from 2002, average prices have generally not changed by more than $5 to $10. However, Figure 5-2 illustrates how price volatility has been dramatically reduced over the past 2 years. With less volatility and generally low average prices in 2004, coupled with the $50/MWh bid-floor, there were subsequently fewer opportunities for demand response to participate in the market through DADRP.

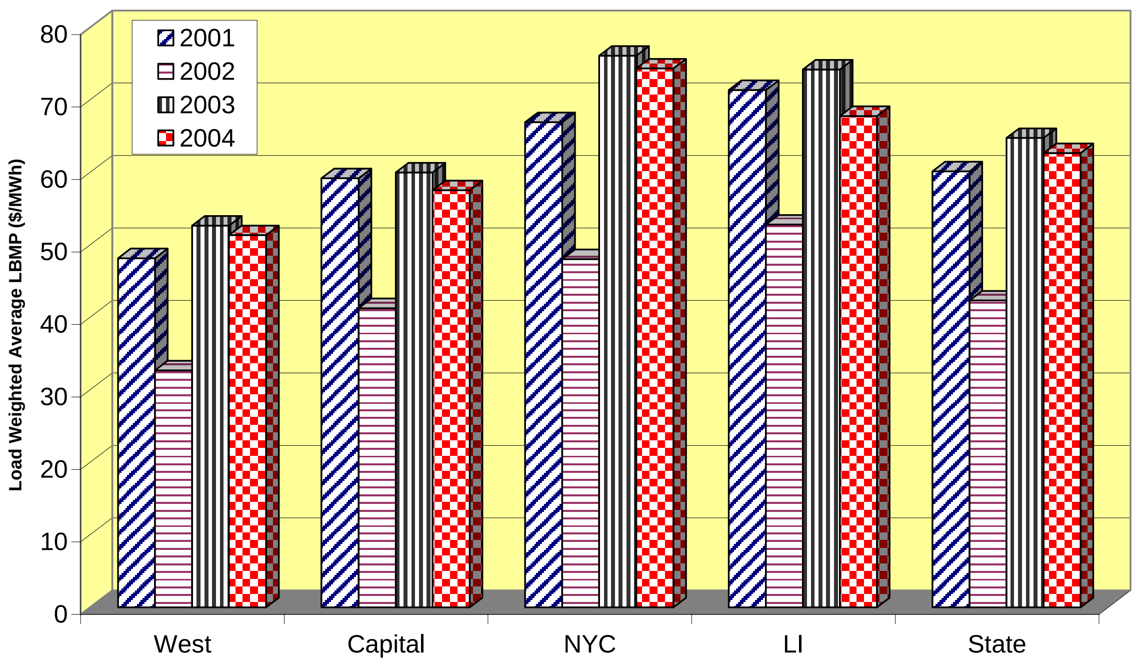


Figure 5-1 Average Prices in NYISO's Day-Ahead Market by Region and Program Year (Noon through 7 p.m.)

In the NYISO's Real-Time market, similar trends were observed. Average prices have remained relatively constant over the past two years, as shown in Figure 5-3, with volatility being reduced as well (see Figure 5-4).

[14] Program years correspond with the period of September 1 – August 31 of the following year. So Program 2004 represents September 1, 2003 – August 31, 2004.

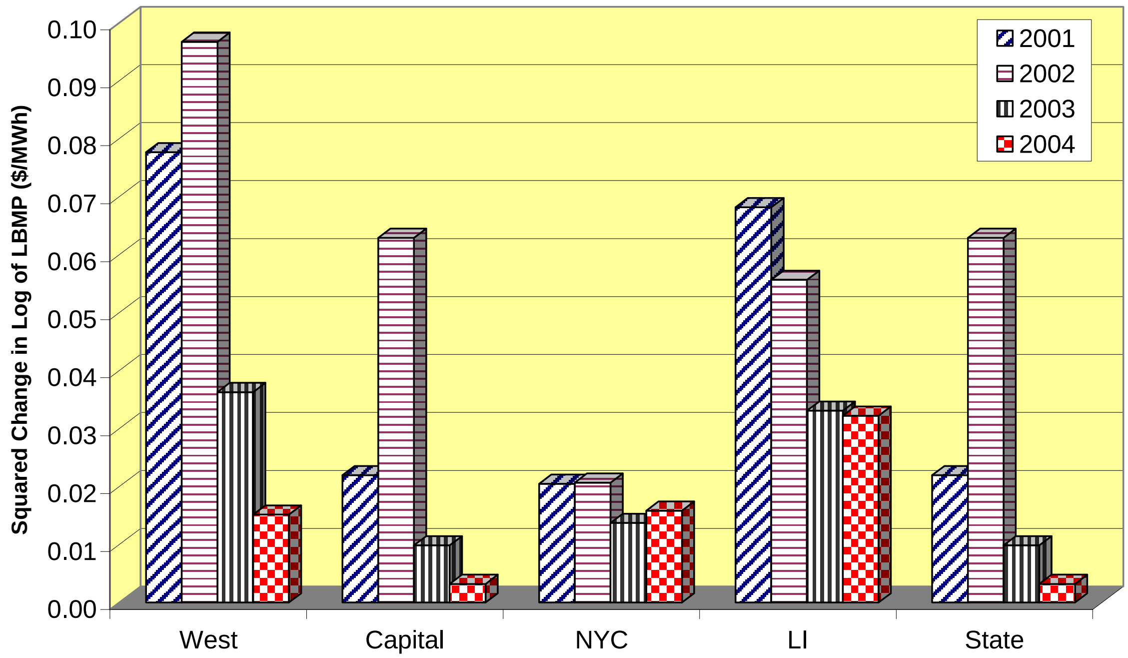


Figure 5-2 Volatility in NYISO Day-Ahead Market by Region and Program Year (Noon through 7 p.m.)

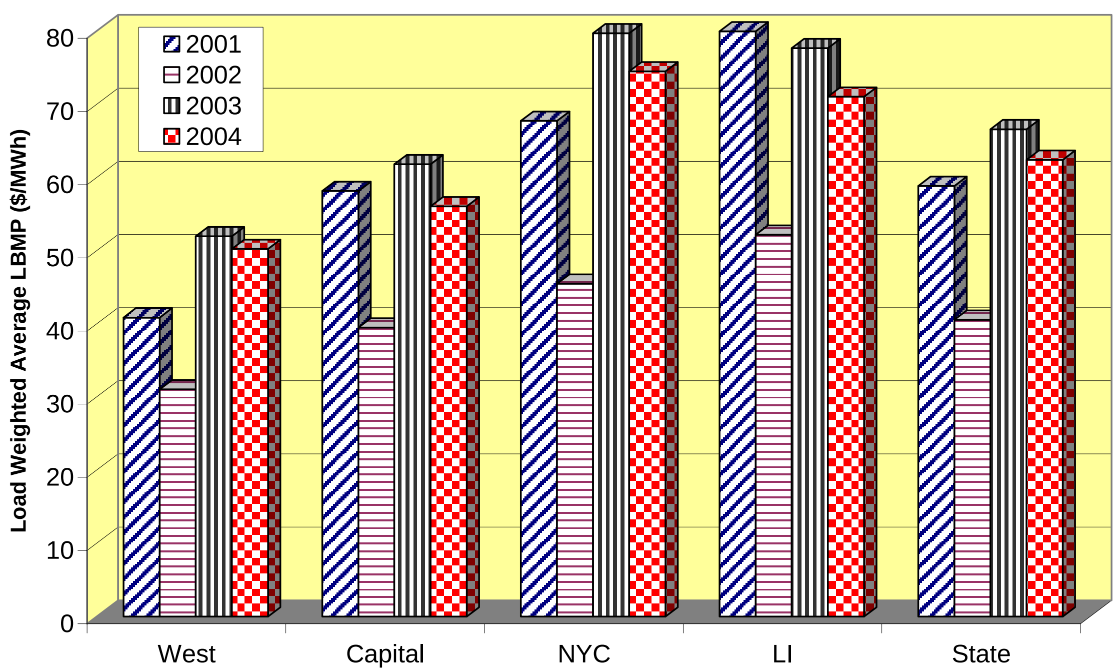


Figure 5-3 Prices in NYISO's Real-Time Market by Region and Program Year (Noon through 7 p.m.)

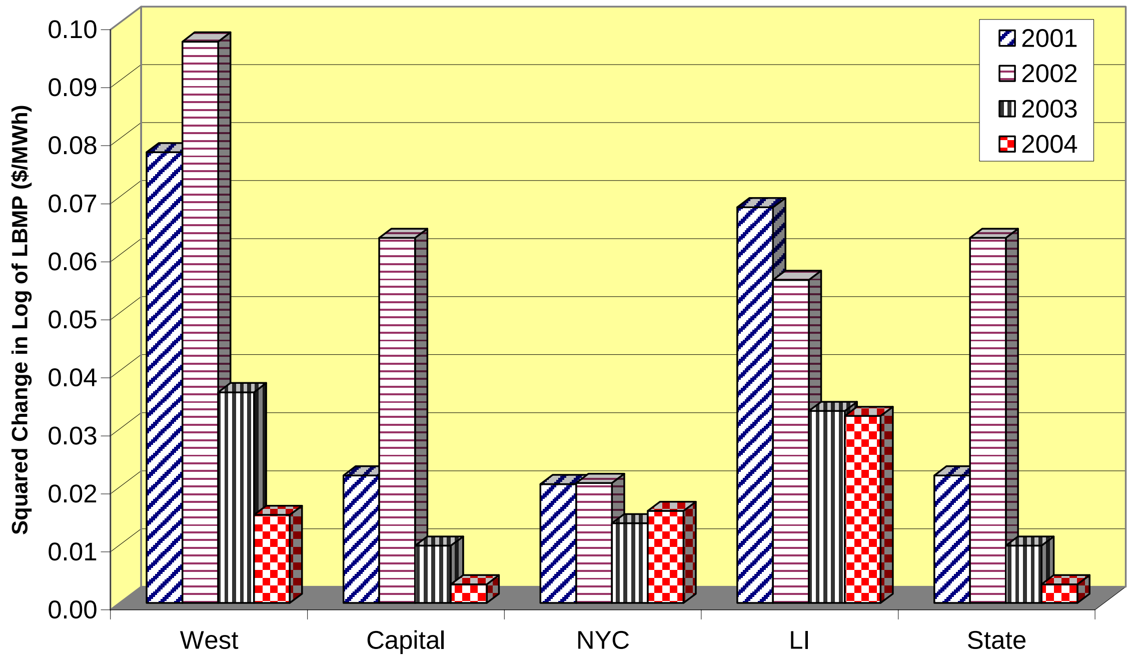
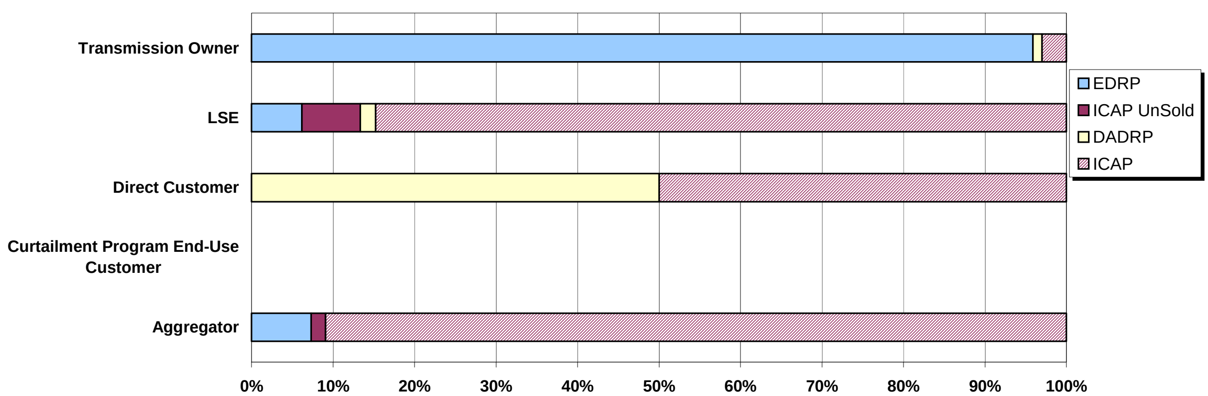


Figure 5-4 Volatility in NYISO Real-Time Market by Region and Program Year (Noon through 7 p.m.)

Appendix B - Program Participation and Migration

Program Participation

Figure 5-5, below, illustrates the type of CSP that participants are enrolling with. Clearly, transmission owners (TOs) have the majority of the EDRP participants (1026), in part due to the tariff-mandated payment split of 90% to participants. Conversely, aggregators and competitive load-serving entities (LSEs) have the majority of the ICAP-SCR participants, 722 and 178, respectively. ICAP-SCR enrollment with a competitive LSE or aggregator does not carry any type of mandated payment split for either capacity or energy. In 2004, there were no Curtailment Program End-Use Customers, also known as Limited Customers, enrolled in any program.



	Aggregator	Curtailment Program End-Use Customer	Direct Customer	LSE	Transmission Owner
ICAP	722	0	1	178	32
DADRP	0	0	1	4	12
ICAP UnSold	14	0	0	15	0
EDRP	58	0	0	13	1026

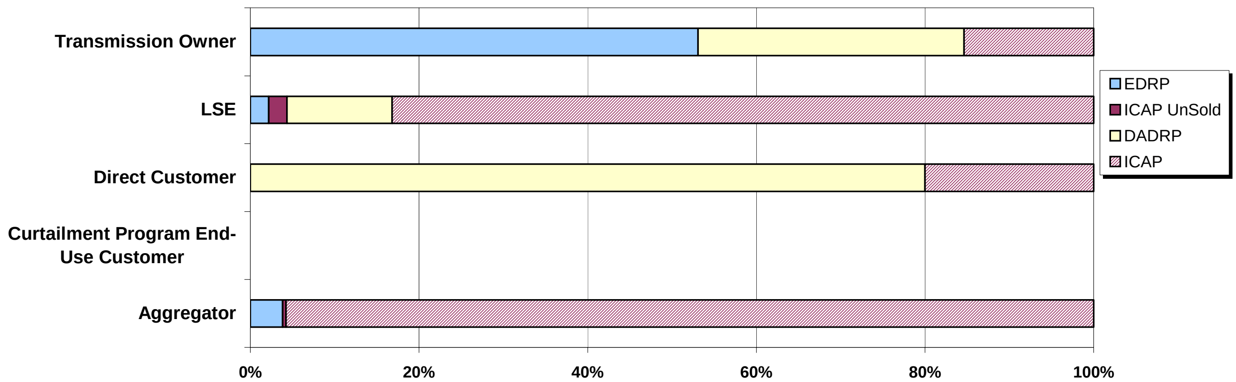
Figure 5-5 Program Enrollment by CSP Type

In Figure 5-6, the subscribed MW by program and CSP type is shown. While the TOs have enrolled over 90% of the participants in the EDRP program, those participants make up just over half of the subscribed MW (542 MW) it registered for NYISO demand response programs in 2004. Approximately 40% of the TOs' enrolled MW come from the DADRP program (322 MW), with the remaining 15% enrolled in the ICAP-SCR program (157 MW).

The bulk of the load subscribed by competitive LSEs and aggregators is in the ICAP-SCR program (310 MW and 512 MW, respectively), with 5% or less enrolled in the

EDRP program. Competitive LSEs who qualify as Demand Response Providers in the DADRP program have about 10% of their subscribed MW enrolled (46 MW).

Direct customers enrolled 80% of their load (8MW) into the DADRP program.

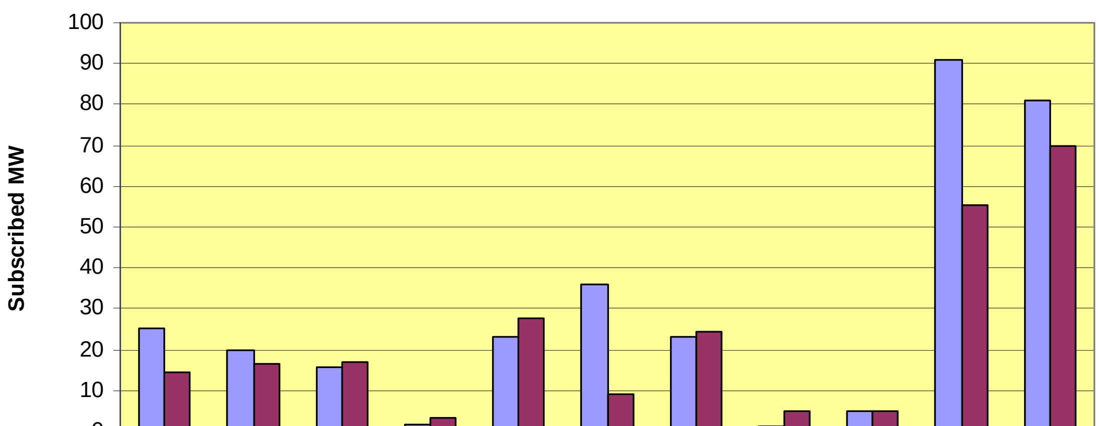


	Aggregator	Curtailment Program End-Use Customer	Direct Customer	LSE	Transmission Owner
ICAP	512.0	0.0	2.0	309.9	156.9
DADRP	0.0	0.0	8.0	46.5	322.4
ICAP UnSold	2.2	0.0	0.0	8.1	0.0
EDRP	20.5	0.0	0.0	8.1	542.1

Figure 5-6 Subscribed MW by CSP Type

Curtailment Type

Figure 5-7, Subscribed MW by Curtailment Type, shows the distribution of subscribed MW across the 11 NYISO price zones and the amount by curtailment type of either load or generation. In 2004, approximately 44% of the subscribed load (247 MW) in the



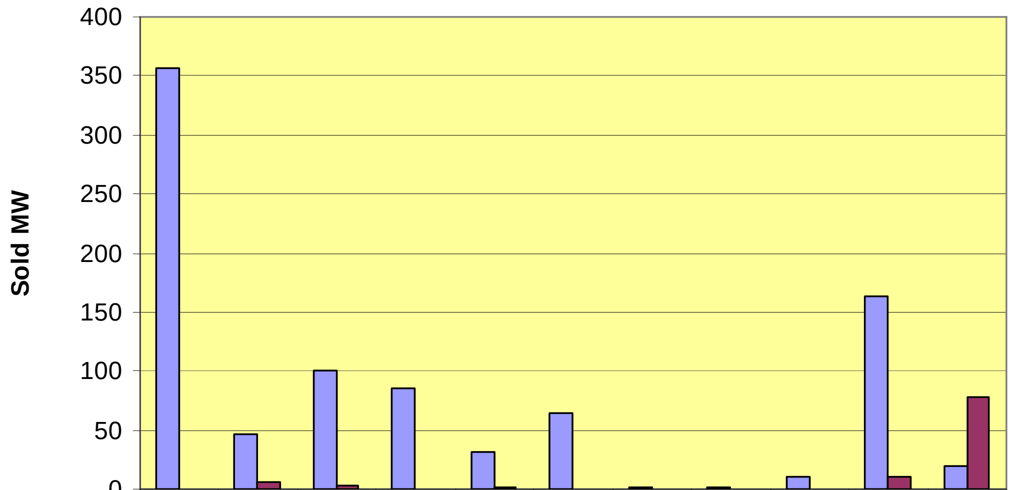
	A	B	C	D	E	F	G	H	I	J	K
Load	25.1	20.0	15.7	1.7	23.3	35.8	23.0	1.2	5.0	91.0	80.9
Gen	14.3	16.5	16.9	3.4	27.5	9.2	24.3	5.0	4.9	55.5	70.0

NYISO Price Zones

Figure 5-7 Subscribed MW by Curtailment Type

EDRP program came from generation, with the majority from two zones, J – NYC (55MW/22%) and K-Long Island (70MW/28%).

Figure 5-8, Sold MW by Curtailment Type - ICAP-SCR Resources, shows the distribution of load and generation curtailment types for sold ICAP-SCR resources where only 11% of the program's curtailable resources are supplied by generation. As with the EDRP program, the majority of resources using generation are in New York City (zone J) with 11.1 MW, and Long Island (zone K) with 77.9 MW.



	A	B	C	D	E	F	G	H	I	J	K
Load	357.1	45.8	100.0	84.7	30.8	64.0	1.4	2.2	10.7	163.6	19.9
Generation	0.5	6.5	3.6	0.0	0.8	0.0	0.0	0.0	0.2	11.1	77.9

NYISO Price Zones

Figure 5-8 Sold MW by Curtailment Type - ICAP-SCR Resources

Participation Trends 2001 – 2004

NYISO's demand response programs have been in effect for four summers, which allows for a study of trends beyond the year-to-year program migration studies.

Figure 5-9, Number of Participants enrolled by Program, illustrates the overall enrollment by number of program participants as of August of each year. Program participation in EDRP increased approximately 750% from 2001 to 2002 and the number of participants has gradually tapered off about 15% each subsequent year.

ICAP-SCR participation increased slightly in 2002, decreased slightly in 2003 and rebounded to almost 300 participants in 2004. What is not evident from this participation chart is how an administrative change affected program participation counts for ICAP-

SCR. The main document describes how, beginning with the summer of 2004, ICAP-SCR resources which contained aggregated participants are required to individually enroll each participant as part of an aggregation. During the first three years of the ICAP-SCR program, the aggregation was counted as a single resource, even though there may have been tens of participants, or more, in the aggregation. The note below the chart explains that for 2004, there were 933 individual participants in ICAP-SCR, while the chart indicates just under 300 resources (Table 1-1of the main report provides further detail on how the ICAP-SCR resources and participants are distributed between aggregations and individual resources).

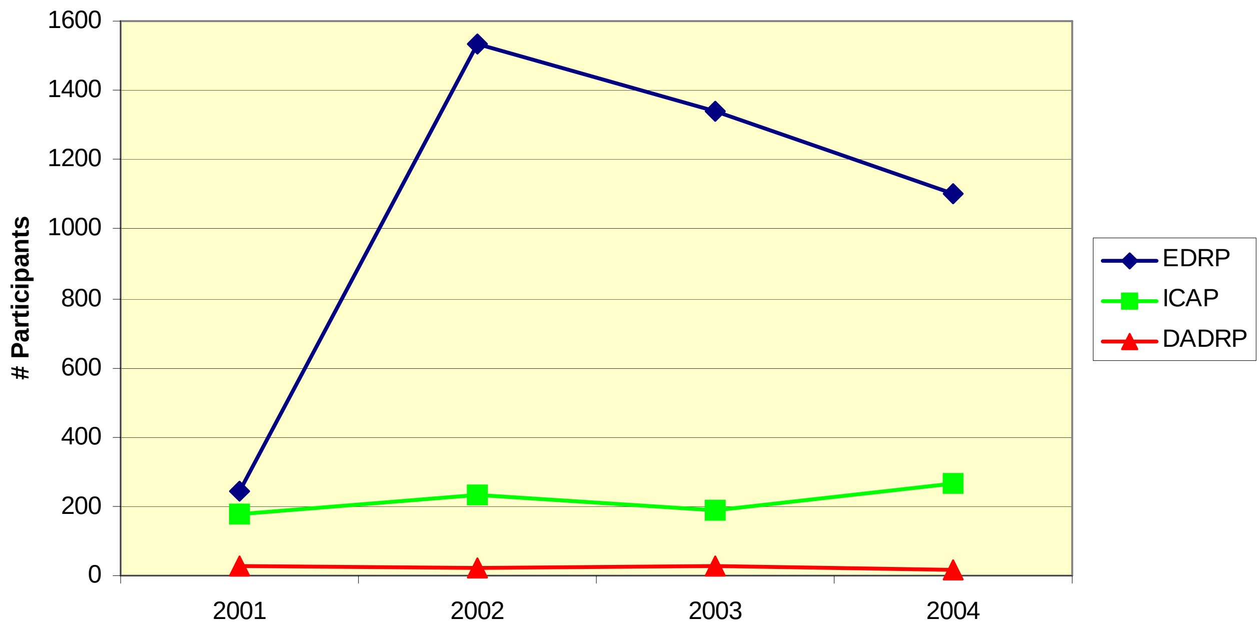


Figure 5-9 Number of Participants enrolled by Program

***NOTE:** This chart uses the number of ICAP-SCR Resources, not individual participants, to permit comparison with the prior year's enrollment information. There were 933 individual participants in the ICAP-SCR program in 2004; data on individual participants is not available for prior years.

The subscribed MW by program and year are shown in Figure 5-10. The MW subscribed to EDRP over the four summers initially increase to almost 1000 MW in 2002, but has tapered off to less than 600 MW in 2004. ICAP-SCR continues to increase the subscribed/sold MW in its program from approximately 300 MW in 2001 to almost 1000 MW in 2004. The DADRP program had sustained its subscribed MW for three years, with a slight drop in 2004.

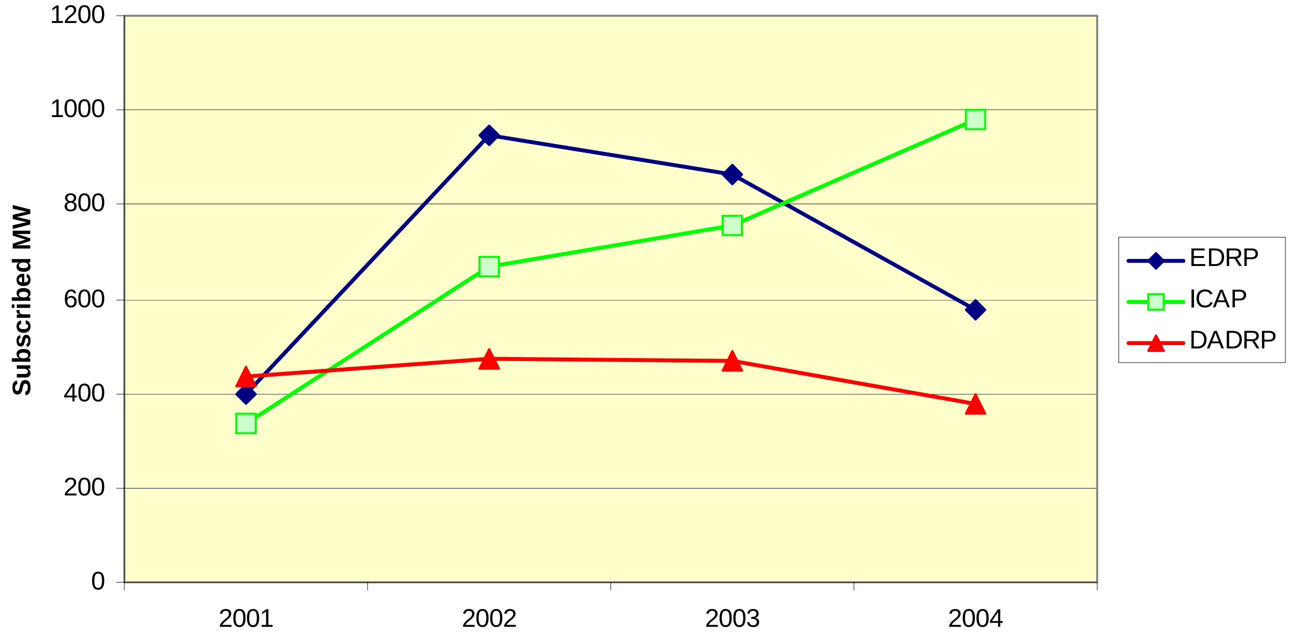


Figure 5-10 Subscribed MW by Program

The following figure, Figure 5-11, plots the program churn over the past four years. Participants who had never been in a NYISO demand response program are identified as NEW and participants who withdrew from participation in any or all NYISO demand response programs are identified as DROP. Participants who moved from one NYISO program to another will be discussed under section 9, Program Migration.

The EDRP program showed the largest single jump in number of new participants in 2002 when more than one thousand new participants enrolled in the program. Between 2002 and 2003, about 500 participants who had been enrolled in EDRP left the program and did not enroll in any other NYISO demand response program. A comparable number of EDRP participants left demand response programs between 2003 and 2004.

Regarding EDRP program churn:

It should be noted that it is possible that some of the participants who appear to have dropped out of all NYISO programs may have been enrolled in as part of an ICAP-SCR aggregation in 2002 or 2003. Detailed ICAP-SCR participant aggregation records were not available for these years, thus participants counted as dropped may have migrated to ICAP-SCR.

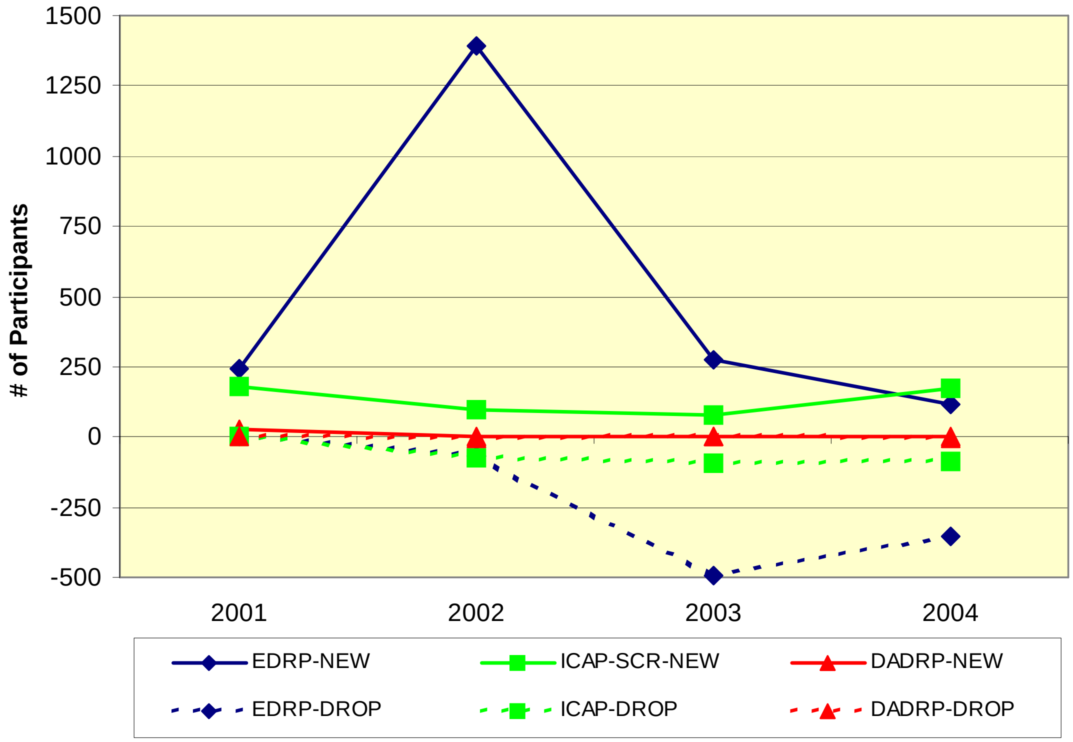


Figure 5-11 Program Churn by Number of Participants and Program

The number of new participants in the ICAP-SCR program remained relatively stable, with a low of approximately 100 new participants in 2003 to over 200 in both 2001 and 2004. Aggregations may account for the slower rate of growth of new participants in ICAP-SCR as aggregations were formed in 2002 and 2003, showing only a single resource when multiple participants were actually joining.

DADRP program enrollment has also remained stable since its inception in 2001, with the largest net enrollment increase of 4 in 2002, and the largest net decrease of 4 between 2003 and 2004.

Figure 5-12 below shows the MW subscribed from year to year. The changes in subscribed MW, especially in ICAP-SCR, provide a far more interesting view of the trends in each program in terms of the amount of load demand response resources subscribe to the programs. More new curtailable load continues to join the ICAP-SCR program than either of the other programs, especially after the summer of 2002. While ICAP-SCR subscribed MW grew by 626 MW between 2003 and 2004, new MW enrolled in EDRP amounted to 38 MW for the same period.

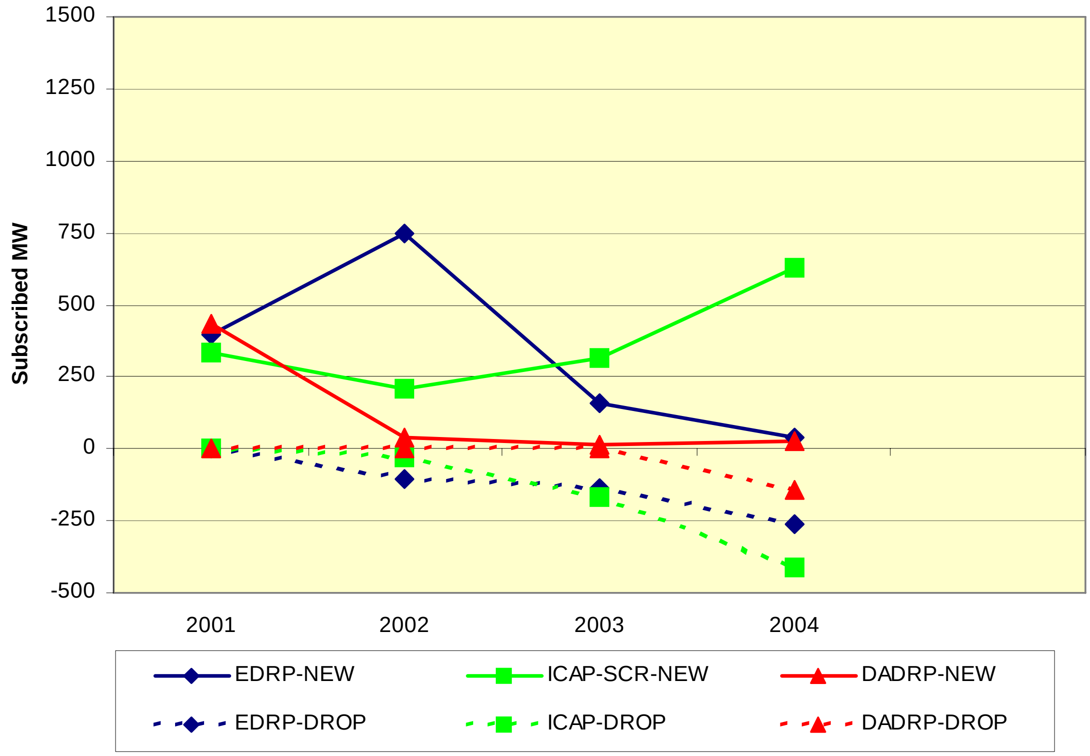


Figure 5-12 Program Churn by Subscribed MW and Program

On average, resources in EDRP subscribe significantly smaller curtailable amounts than ICAP-SCR, approximately seven times smaller (average EDRP resource 0.52MW, average ICAP-SCR resource 3.66MW, see Table 2-4 of the main document).

ICAP-SCR appears to be the more attractive program for customers who are confident about their ability to curtail, since the ICAP-SCR program has financial penalties for non-compliance. The program offers a guaranteed payment for capacity with the option for additional payment for energy, should an event be called. Additionally, ICAP-SCR resources may be aggregations that represent tens or hundreds of individual participants. Conversely, EDRP does not offer a guaranteed payment, nor does it have financial penalties, so financial benefits from the program are limited to when events are called.

Program Retention and Migration

Migration

Two important measures of program performance are retention and migration. Retention is defined as a customer remaining in a program two consecutive years, including the current reporting year. Migration is defined by a customer changing from the program it participated in the previous year to a new NYSIO program in the reporting year. Figure 5-13 shows the net migration, by year, for each of NYISO's programs. Net migration refers to the net change in enrollment in a program, both transfers into and out of a program. Chapter 2 provides a full description of program migration. Figure 2-8 of the main document details the transfers into and out of each program.

In the figure below (Figure 5-13), movement between EDRP and ICAP is self-evident. For example, in 2002, the net change in EDRP was -30 participants while ICAP-SCR shows a net gain of 30 participants. Between 2002 and 2003, ICAP-SCR had a net decrease of 29 resources while EDRP had a net gain of 25 resources. Both programs had a net loss of 3 resources between 2003 and 2004. DADRP had a net loss of one or two participants in 2002 and 2003, and a net loss of 6 participants in 2004.

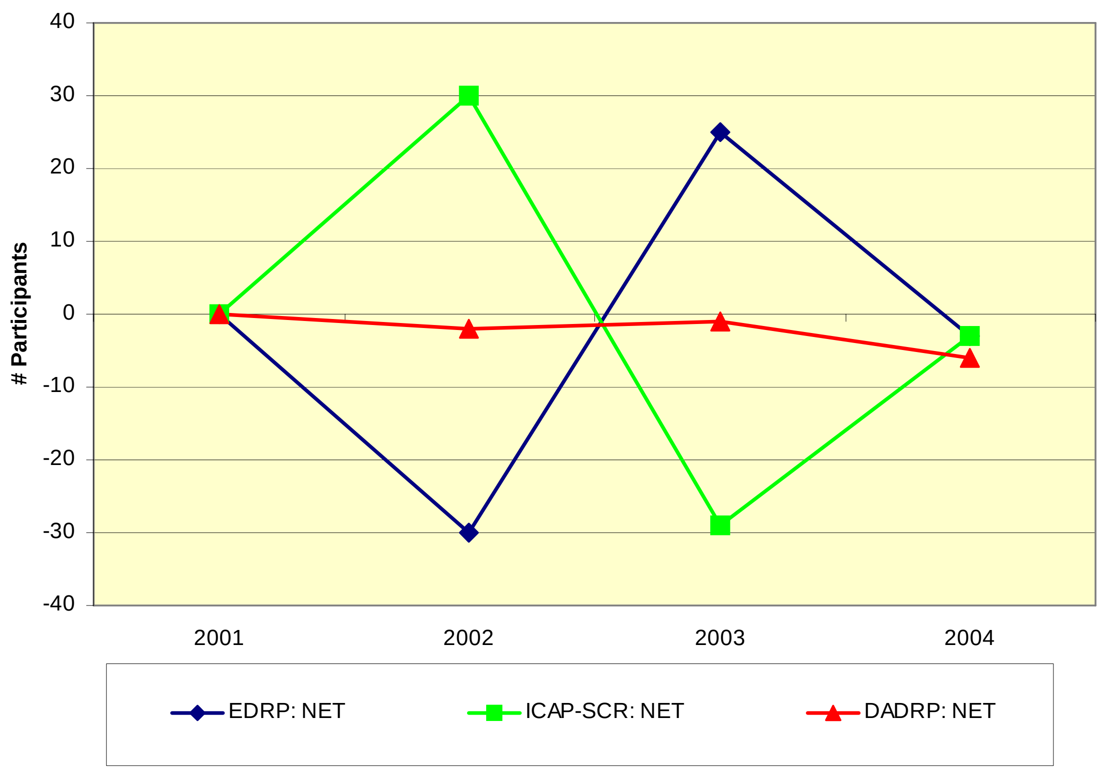


Figure 5-13 Program Migration - Net Change in Number of Participants

Figure 5-14, Program Migration - Net Change in Subscribed MW, shows the net changes in subscribed load associated with the annual migrations among programs. EDRP had an average net loss of 69 MW per year from migration over the three years since its inception. ICAP-SCR had a net gain of over 95 MW from migration in 2002, followed by a net loss of 34 MW in 2003 and approximately 3MW in 2004, for an average gain of 20 MW per year from migration. DADRP had no migration from 2001 to 2002, a net loss of 14 MW from 2002 to 2003 and a net gain of 19.6 MW from 2003 to 2004.

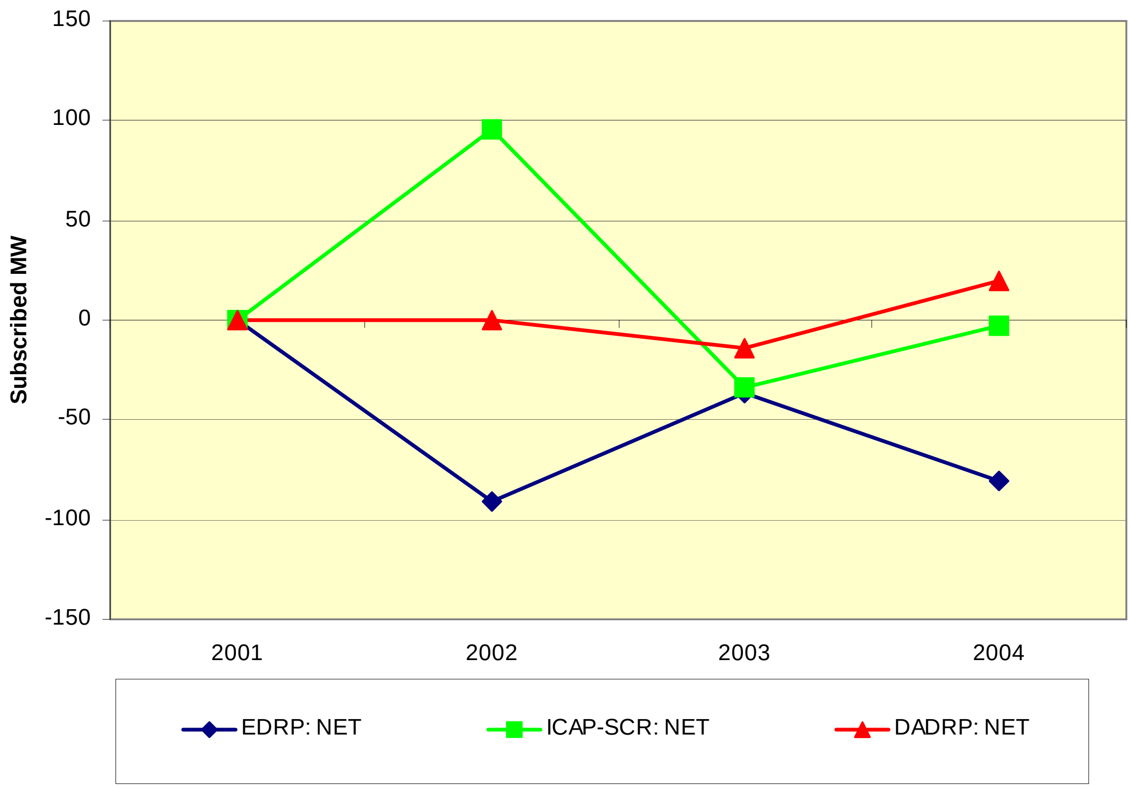


Figure 5-14 Program Migration - Net Change in Subscribed MW

Retention

The complement to program churn and migration is retention. Table 5-1 shows the annual and the average retention rates for participants in each program.

	EDRP	*ICAP-SCR*	*DADRP*
2002	58.4%	74.6%	80.0%
2003	69.5%	47.0%	95.8%
2004	73.4%	51.1%	60.0%
Average	67.1%	57.5%	78.6%

Table 5-1 Program Retention Statistics

Although DADRP has the lowest number of participants, the program's retention rate was very high for the second and third years and the highest overall. EDRP, with the largest number of participants retains about 2/3 of its participants. ICAP-SCR showed a dramatic reduction in retention from 2002 to 2003 and averages a retention rate of over 50%.

Participants have the ability to adjust their subscribed curtailment each capability period. The focus of this evaluation is on the status of the programs as of August of each year; therefore subscribed curtailment changes reflect the difference between the previous summer, not the previous capability period, and the current one. Figure 5-15 shows the changes in subscription by program and year for re-enrolled program participants. This chart essentially reflects adjustments to participants' ability to estimate their curtailment capability. When adjustments are negative, re-enrolling participants overestimated their curtailment capability in the previous year. Adjustments in the positive direction may be attributed to factors such as: installation of enabling technologies or energy efficiency measures to increase curtailment capability, adjustment to a conservative estimate based on experience in the prior year, or an increase in an aggregation resource (ICAP-SCR).

Since NYISO's demand response programs began, the net change in re-enrolled MW subscriptions is:

- EDRP: -51.8 MW (9% of 2004 subscribed EDRP MW)
- ICAP-SCR: 47.3 MW (5% of 2004 subscribed ICAP-SCR MW)
- DADRP: 0 MW

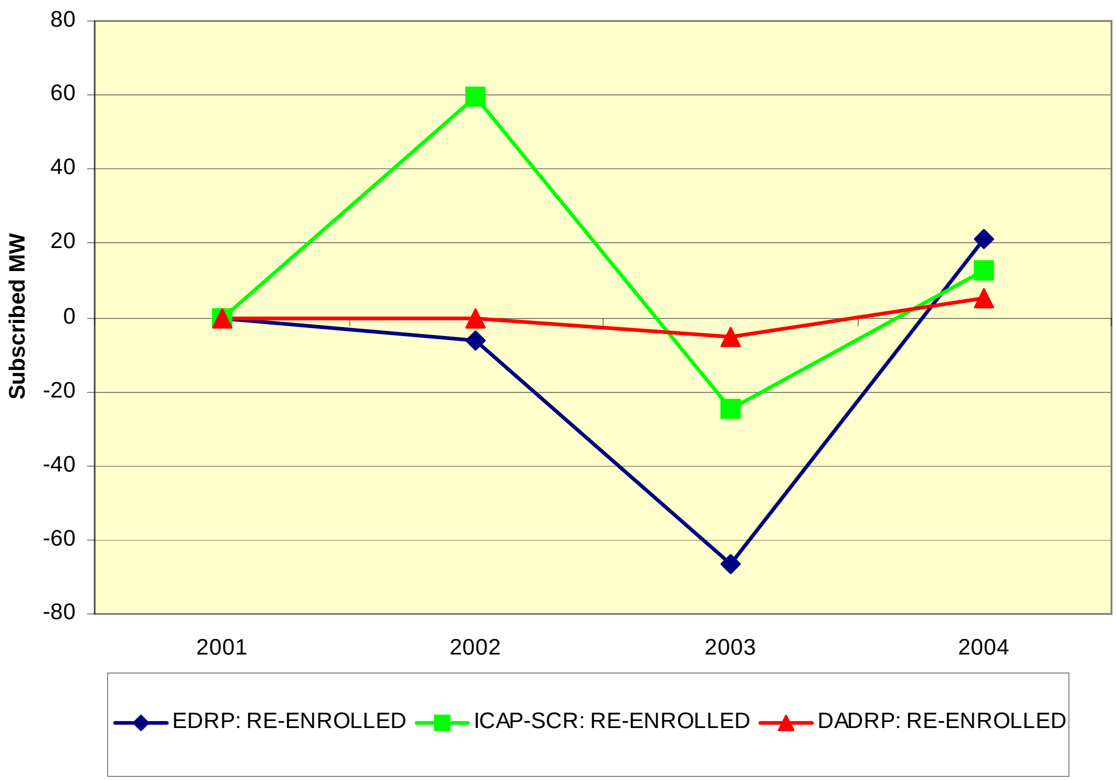


Figure 5-15 Changed to Subscribed MW for Re-enrolled Participants

Appendix C – Benefits Evaluation Methodology

The "Spline" Formulation of the Supply Curve

To capture the "hockey stick" nature of electricity supply, it is necessary to use a "spline" formulation of supply in which we identify points (often called knots) at which the supply relationship changes its structure. For our purposes, these "knots" are defined to isolate the ranges in load for which the supply envelope is functionally different. We hypothesize that three regimes should be sufficient, however there are cases in which two regimes are sufficient. Assuming a log-linear specification, we begin by defining three zero-one variables, one for each segment of load (e.g., fixed bid load or actual load depending on which market is being estimated) measured in logarithmic terms (ln L):

(1) $D_1 = 1$ if $\ln L \leq \ln L_1^*$, otherwise $D_1 = 0$;

(2) $D_2 = 1$ if $\ln L_1^* < \ln L \leq \ln L_2^*$, otherwise $D_2 = 0$;

(3) $D_3 = 1$ if $\ln L > \ln L_2^*$, otherwise $D_3 = 0$.

where L = fixed bid load or real time load and the subscripts indicate specific MW loads.

The Linear "Spline" Function

Now, for a linear "spline" specification, the inverse supply relation is given by:[15]

(4) $\ln LBMP = \alpha_1 D_1 + \alpha_2 D_2 + \alpha_3 D_3 + \beta_1 D_1 \ln L + \beta_2 D_2 \ln L + \beta_3 D_3 \ln L.$

This specification is a simple dummy variable regression. But in its unconstrained form, there is no guarantee that the value of the fitted function coming into a "knot" is equal to the value of the function coming out of the "knot". We impose constraints to ensure that this requirement is met for internal consistency of the piece-wise function. Thus, to rule out jumps in the fitted values of the dependent variable, we must constrain the function (4) in the following way (Ando, 1997 and Neenan Associates, 2002):

(5) $\alpha_1 + \beta_1 \ln L_1^* = \alpha_2 + \beta_2 \ln L_1^*$ or $\alpha_1 = -\beta_1 \ln L_1^* + \alpha_2 + \beta_2 \ln L_1^*$.

(6) $\alpha_2 + \beta_2 \ln L_2^* = \alpha_3 + \beta_3 \ln L_2^*$ or $\alpha_3 = -\beta_3 \ln L_2^* + \alpha_2 + \beta_2 \ln L_2^*$.

[15] For computational convenience and additional flexibility in the model, this function is actually specified to be linear in logarithms. The subscripts for zone and time of day have been suppressed for notational simplicity.

The resulting constrained regression (equation (4) subject to equations (5) and (6)) can be estimated by ordinary least squares (OLS), through simple variable transformations made possible by solving equations (5) and (6) for α_1 and α_3, and then substituting the results into equation (4). In this way, we eliminate all of the intercept terms except α_2, and we are left with the following specification:

(7) $\ln LBMP = \alpha_2 \{ D_1 + D_2 + D_3\} + \beta_1 \{ D_1 [\ln L - \ln L_1^*]\} + \beta_2 \{ D_1 \ln L_1^* + D_2 \ln L + D_3 \ln L_2^*\} + \beta_3 \{ D_3 [\ln L - \ln L_2^*]\}$.

In the data, the three zero-one variables add to a vector of ones. Thus, the first term in equation (7) reduces to a standard intercept term in OLS. All parameters of the original model are identified from this regression, except for α_1 and α_3. These parameters are identified after the fact by using equations (5) and (6).

Once equation (7) is estimated and the remaining parameters are identified, we can use equation (4) to calculate the supply price flexibilities. These flexibilities will differ in each regime of the spline function. That is, the partial logarithmic derivatives of equation (7) with respect to the logarithm of L are:

(8) $\partial \ln LBMP / \partial \ln L = \beta_1$, if $\ln L \leq \ln L_1^*$;

(9) $\partial \ln LBMP / \partial \ln L = \beta_2$, if $\ln L_1^* < \ln L \leq \ln L_2^*$;

(10) $\partial \ln LBMP / \partial \ln L = \beta_3$, if $\ln L > \ln L_2^*$.

Thus, while these supply price flexibilities are constant over the corresponding ranges in load defined by the knots, this model allows them to differ across the intervals. Our principle hypothesis is that the price flexibilities will be positive and will rise as load rises—that is $\beta_1 < \beta_2 < \beta_3$. We constrain the calculated value of lnLBMP at the three “knots” to be equal in approaching the “knot” from either direction; it is these constraints that allow the flexibilities to differ. From equation (5) we see that $\beta_1 < \beta_2$, as long as $\alpha_1 > \alpha_2$. Likewise, $\beta_2 < \beta_3$ as long as $\alpha_2 > \alpha_3$.

A More Complex “Spline” Formulation

This linear “spline” formulation adds tremendous flexibility to the supply model, but it still requires that the price flexibility is constant within a particular interval of L. To relax this restriction, we need only make this formulation non-linear in the logarithm of L. Further, if there are other factors that affect supply, we can capture them by incorporating variables that shift the supply curve. Each of these refinements in the model is discussed in detail in Neenan Associates (2002), but they can be summarized in the following way. The model now includes a variable X that shifts all segments of the function in the same fashion and an interaction term, X lnL (e.g., X multiplied by lnL), whose slope differs between the "knots".[16] The "spline" equation becomes:[17]

(11) $\ln LBMP = a_1D_1 + b_1D_1X + c_1D_1 \ln L + d_1D_1 X \ln L + a_2D_2 + b_2D_2X + c_2D_2 \ln L + d_2D_2 X \ln L + a_3D_3 + b_3D_3X + c_3D_3 \ln L + d_3D_3 X \ln L$

The constraints to assure that the function has the same value coming into and going out of the knots are given by:

(12) $a_1 + b_1X + c_1 \ln L_1^* + d_1X \ln L_1^* = a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^*$

(13) $a_3 + b_3X + c_3 \ln L_2^* + d_3X \ln L_2^* = a_2 + b_2X + c_2 \ln L_2^* + d_2X \ln L_2^*$.

By placing these constraints on the function at these "knots", we force the values of lnLBMP to be equal regardless of the direction from which we approach the "knot" without the corresponding parameters all being equal to one another. Suppose, for example, that we want the marginal effect of a change in lnL on lnLBMP to be higher for values of lnL across successive knots. A sufficient, but certainly not a necessary condition, for this to happen is for $c_3 > c_2 > c_1$; $d_3 > d_2 > d_1$; and $a_1 > a_2 > a_3$. If this were merely a linear "spline" function in lnL, the b's, and d's would all be zero, and the sufficient condition above would involve only the c's and the a's.

To estimate this model using OLS, we must again solve the two equations above for a_1 and a_3:

(14) $a_1 = a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^* - [b_1X + c_1 \ln L_1^* + d_1X \ln L_1^*]$; and

(15) $a_3 = a_2 + b_2X + c_2 \ln L_2^* + d_2 \ln L_2X^* - [b_3X + c_3 \ln L_2^* + d_3X \ln L_2^*]$.

Substituting these expressions into equation (11), we have;

(16) $\ln LBMP = D_1 \{a_2 + b_2X + c_2 \ln L_1^* + d_2X \ln L_1^* - [b_1X + c_1 \ln L_1^* + d_1X \ln L_1^*]\} + b_1D_1X + c_1D_1 \ln L + d_1XD_1 \ln L + a_2D_2 + b_2D_2X + c_2D_2 \ln L +$

[16] By allowing for interactions between the variable over which the "spline" is defined and other continuous or discrete variables, not only can we accommodate factors that shift supply for a given quantity, but we can also accommodate a specification that is non-linear in the logarithm of load by setting the shifter variable equal to the logarithm of load.

[17] When X = lnL, the model becomes quadratic in lnL.

$d_2D_2X \ln L + D_3 \{ a_2 + b_2X + c_2 \ln L_2^* + d_2X \ln L_2^* - [b_3X + c_3 \ln L_2^* + d_3X \ln L_2^*]\}+ b_3D_3X + c_3D_3 \ln L + d_3D_3X \ln L$.

Combining those terms for which there is a common parameter, we have:

$$\text{(17)} \quad \ln LBMP = a_2 [D_1+ D_2+ D_3]+b_1 [D_1 X–D_1X]+b_2 [D_1X+ D_2X+D_3X]+b_3 [D_3X-D_3X] + c_1 [D_1 \ln L – D_1 \ln L_1^*] + c_2 [D_1 \ln L_1^* + D_2 \ln L + D_3 \ln L_2^*] + c_3 [D_3 \ln L – D_3 \ln L_2^*] + d_1 [D_1X \ln L – D_1X \ln L_1^*] + d_2 [D_1X \ln L_1^* + D_2X \ln L + D_3X \ln L_2^*] + d_3 [D_3 \ln L – D_3 \ln L_2^*]$$

Again, since the sum of the zero-one variables, $[D_1+ D_2+ D_3]$ is unity, and the terms associated with b_1 and b_3 are zero, a_2 becomes an intercept term, and X, the variable that shifts the function in the same way across “knots”, becomes a standard level term in the regression. This means that a_2, the intercept for the second segment, is identified directly in the regression along with the other coefficients, but a_1 and a_3 must be evaluated using equations (14) and (15). We cannot identify b_1 and b_3, but that is as it should be because we have assumed that X shifts the function identically regardless of the value of lnL, and this shift is captured by b_2. This is not true for the slope of the function, because of the interaction between X and lnL.

The marginal effects of the independent variables on the value of lnLBMP are of most interest in this model. That is, we want to identify from equation (11) the marginal effects of lnL and X on lnLBMP. Taking the partial derivatives of lnLBMP with respect to lnL for the three segments, we have:

$$\text{(18)} \quad \partial \ln LBMP / \partial \ln L = c_1 + [d_1X], \text{ if } \ln L \leq \ln L_1^*;$$

$$\text{(19)} \quad \partial \ln LBMP / \partial \ln L = c_2 + [d_2X], \text{ if } \ln L_1^* < \ln L \leq \ln L_2^*;$$

$$\text{(20)} \quad \partial \ln LBMP / \partial \ln L = c_3 + [d_3X], \text{ if } \ln L > \ln L_2^*.$$

These marginal effects differ by segment and are now functions of X. The marginal effects of X on lnLBMP would be equal to b_2 for all values of lnL if it were not for the interaction terms between X and lnL. Because of the interaction, the partial derivatives of lnLBMP with respect to X are:

$$\text{(21)} \quad \partial \ln LBMP / \partial X = b_2+ d_1[\ln L], \text{ if } \ln L \leq \ln L_1^*;$$

$$\text{(22)} \quad \partial \ln LBMP / \partial X = b_2 + d_2 [\ln L], \text{ if } \ln L_1^* < \ln L \leq \ln L_2^*;$$

$$\text{(23)} \quad \partial \ln LBMP / \partial X = b_2 +d_3 [\ln L], \text{ if } \ln L > \ln L_2^*.$$

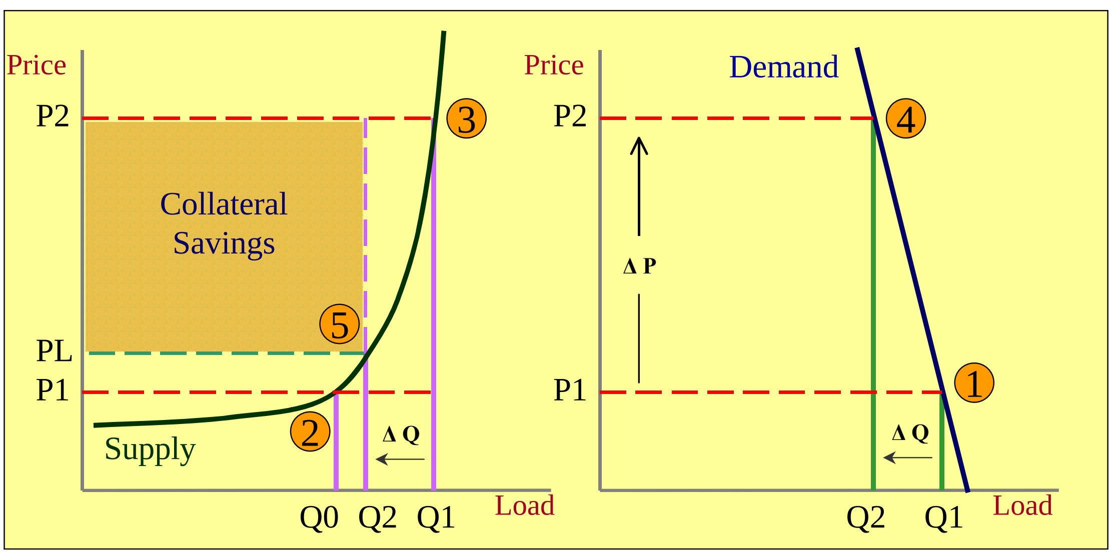
These effects now differ by segment, and they are functions of lnL.

DADRP Benefits Evaluation Methodology

Measuring the Improvement in Electricity Markets from DADRP

In developing the theory underlying market effects of DADRP, it is assumed that demand is initially at a level indicated by point Q1 in Figure 5-16. When the curtailment is scheduled, as the exhibit illustrates, demand is reduced to Q2 due to the load reduction, and the LBMP in the DAM consequently falls from P2 to PL. The situation when a curtailment is scheduled could, in fact, be worse than the one in Figure 5-16. Demand could initially be well beyond Q2, not intersecting the supply curve at all.

In either case, the load relief forthcoming during a scheduled DADRP curtailment would depress market prices as long as the load curtailment results in a shift of the load level to the left of where it otherwise would have intersected the supply curve.



1 Retail rate and corresponding demand.

2 Supply offered at retail rate.

3 Retail demand supplied only at higher price.

4 Reduction in retail demand due to higher price.

5 LBMP after scheduled load reduction.

Figure 5-16: The Dynamics of DADRP Price-Responsive Load

To assess the effects of a scheduled DADRP curtailment, one must essentially view things in reverse order. That is, once a DADRP bid is scheduled, the market equilibrium is at point 1 in Figure 5-16. The observed price and quantity are PL and Q2, respectively. Now, using the estimated supply price flexibilities from above (combined with data on actual DADRP scheduled curtailments), one must simulate what LBMP would have been had the load response not occurred—P2. As indicated in Figure 5-16, the most significant market effects are:

1. Reduction in DAM-LBMP;
2. DADRP Payments;
3. Collateral Benefits, or Savings to Customers;
4. Any Reduction in Average Price or Price Variability.

Measuring the Reduction in Deadweight Social Losses from DADRP

Although assessing the market impacts from DADRP is critical to an overall evaluation of the PRL programs, it is also important to understand the extent to which DADRP may contribute to overall market efficiency. This task can be accomplished by measuring the extent to which DADRP bids, when scheduled, contribute to a reduction in what economists call social deadweight losses. These losses are a result of customers overuse or underuse of electricity when subject to fixed tariffs, compared with what their use would have been if they could, or were forced to, under very specific conditions, respond to market prices. This type of behavior is exactly what is made possible through DADRP.

The full development of this welfare analysis is reported in Boisvert and Neenan (2003)[18]. The essence of the analysis is found in Figure 5-17, where both peak and off-peak demand situations are depicted. The supply curve S, has the "hockey stick" shape, whereas peak and off-peak demands are given by D_p and D_o, respectively.

From the standpoint of DADRP, it is most important to focus on the demand and supply situation during the peak period. If customers face a fixed tariff T, then they will wish to consume X_4* during peak periods. Although customers pay only T/MW at retail, the

[18] Boisvert, R. N. and B. F. Neenan (2003) "Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets" Lawrence Berkeley National Laboratory LBNL 52530, August.

wholesale price suppliers would require to deliver X_4* is P_4*. While the nature of electricity markets requires LSEs to purchase sufficient energy to meet demand X_4*, in economic terms, the market cannot clear at this quantity and price T, because the supply curve does not pass through that point. In contrast, if customers faced full wholesale prices in the competitive market, the market would clear at price P_4^c and quantity X_4^c. The inefficiency of the fixed tariff results from the fact that, for all units of consumption between X_4^C and X_4*, the marginal cost (given by the supply curve) of meeting this load is higher than its value to the customer (given by the demand curve).

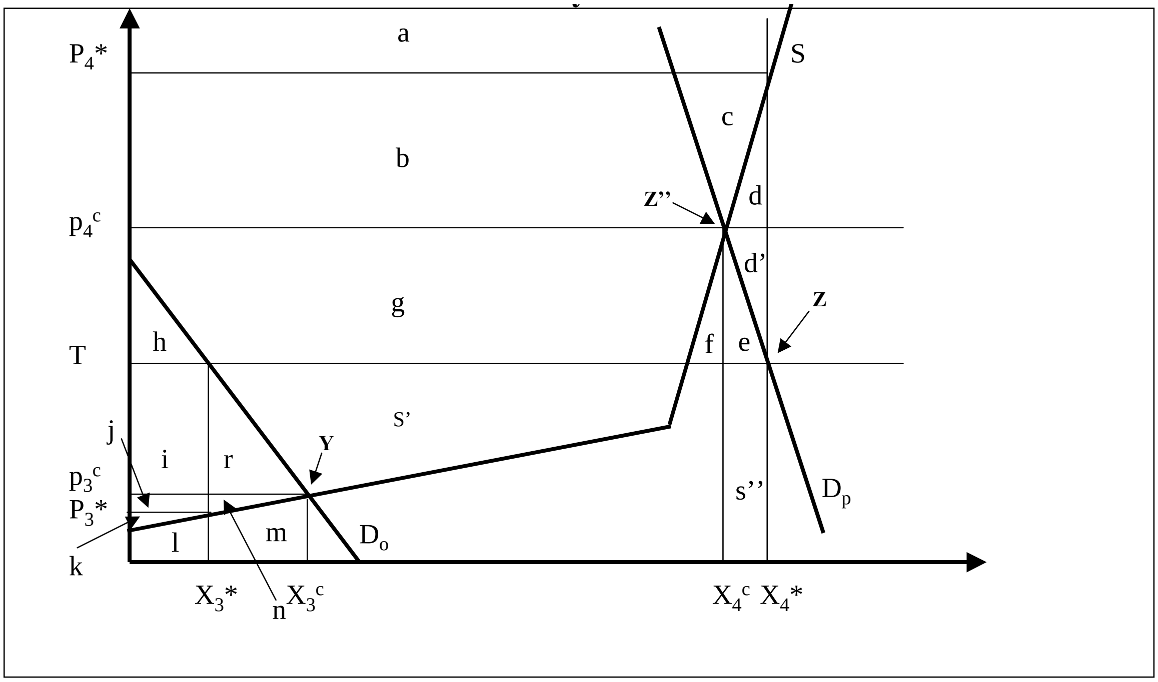


Figure 5-17: Net Welfare Gain from ISO DR Programs in Competitive Electricity Markets

The total difference between the value to customers and the cost to producers over the load range X_4* - X_4^C can be shown to be equal to the area d + d' in Figure 5-17. However, some of this social deadweight loss can be avoided through DADRP if:

- ❑ Customers bid load reduction equal to X_4* - X_4^C at any offer price at or below P_4^c., and
- ❑ The DADRP payment (equal to the area s" + e + d') is less than the deadweight loss (the area d + d'). For this to be true, the area s" + e must be less than the area d.

This situation can be viewed in two different ways. The first relates to the characteristics of supply and demand if firms have an incentive to respond to price and achieve the equilibrium defined by point Z'' in Figure 5-17. Viewed from this perspective, it is clear that as the supply curve becomes steeper (e.g. pivoting counter clockwise around point Z''), the net welfare from a DR program increases because the area d becomes larger. Similarly, if the initial demand curve were less price responsive (made steeper by pivoting clockwise about the competitive equilibrium z'') the net welfare calculation would also move in favor of the DR load, as the areas e and s'' would both become smaller. In summary, the potential welfare gains from DR load programs are highest in situations where both the supply and demand curves are initially extremely price inelastic ("steeper"). These are the very circumstances that have lead to price spikes that disrupt newly formed wholesale markets.

The size of these two areas is clearly an empirical question, and an important part of this year's PRL evaluation is an attempt to measure the reduction in this social deadweight loss from the past three years' of DADRP bids. In so doing, however, it is important to recognize that because of the NYISO's two settlement system, bids accepted under DADRP produce efficiency gains (reductions in deadweight losses) in both the DAM (when the load is initially scheduled) and in the RTM (when the load does not show up in real time). Payment is made only once.

In discussing these potential gains in the RTM, one must also recognize that if the price in the RTM is less than in the DAM on which they were scheduled to curtail, it can be seen that market efficiency is increased by letting customers who had DADRP bids accepted in the DAM buy through in real time and consume the extra electricity. This result speaks directly to the long- term efficacy of DADRP.

Appendix D – More Detailed Explanation of Estimated Benefits

The NYISO wholesale electricity markets look functionally different at different points in the year. Generally speaking, the fall and spring load and price characteristics look reasonably similar due to related weather patterns observed in each season and the unavailability of generators due to bi-annual maintenance periods. The winter months are also different as electric heating loads increase system demand substantially and competition for natural gas between homeowners and generators can cause price-spikes to occur. In contrast, the summer months offer a third regime where load is generally highest and prices may spike during times of prolonged heat and humidity. For these reasons, the 12-month period of September 2003 through August 2004 was broken out into three distinct seasons: Spring and Fall; Winter; and Summer.

Since participants in the Day-Ahead Demand Response Program (DADRP) only came from the Western part of New York and the Capital region, only these two areas of the State are analyzed herein. However, to ensure consistency with previous year's evaluation, all zones West of the Total East transmission interface (i.e. Zones A – E) were modeled jointly, called the Western NY superzone, as were all zones East of the Total East transmission interface and north of NYC (i.e. Zones F – I), called the Hudson River superzone.[19]

As has been shown in previous NYISO evaluations, Neenan Associates uses a series of shifter variables to characterize functional changes in the supply curve that result in similar levels of load producing variable levels of price. The shifter variables included in this year's evaluation analysis are included in Table 5-2. Aside from a few new shifter variables, the major difference in this year's analysis from prior evaluations is the inclusion of autoregressive terms in the error-structure to remove the hypothesized existence of serial correlation. Including such terms produces more efficient estimators (i.e. parameter estimates with smaller standard errors).

[19] Supply flexibility models were estimated for both New York City and Long Island for the summer of 2004 only to maintain consistency of FERC reporting from year to year. These estimated supply models are reported in the tables below but are not discussed specifically in the text because they had no DADRP load scheduled in them.

Variable	Definition
Intercept Shifters Only	
Pk Sin	A sine curve fit for the peak period
Pk Cos	A cosine curve fit for the peak period
Tues	A dummy variable to represent Tuesdays
Wed	A dummy variable to represent Wednesdays
Thurs	A dummy variable to represent Thursdays
Fri	A dummy variable to represent Fridays
Intercept and/or Slope Shifters	
Temperature Heat Index (THI)	National Weather Service temperature heat index calculated using temperature and dew point
Max Previous Day THI	Maximum of previous day's peak period THI
Avg. Previous 3 Day THI	Average of the previous three day's hourly THI
Wgt. Transmission Outages	Transmission outages on select transmission interfaces weighted by their expected effect on the analyzed zone
Wgt. Transmission Constraints	Transmission contraints of select transmission interfaces weighted by their expected effect on the analyzed zone
Positive Forcast Error	If NYISO forecast load is larger than actual RT load, then this variable is the difference between NYISO forecast load and actual RT load. Else 0.
Negative Forcast Error	If NYISO forecast load is smaller than actual RT load, then this variable is the difference between actual RT load and NYISO forecast load. Else 0.
DAM Coverage	The proportion of actual RT load that is covered by day-ahead market load purchases
Log of Generation/ICAP	The natural logarithm of the proportion of generation offered into the day-ahead market and the total amount of NYCA ICAP

Table 5-2 List of Shifter Variables Used in Econometric Supply Models

During the Spring and Fall of 2003/2004, the NYISO’s markets did not experience prolonged periods of high prices (see Appendix 5A.2 for a discussion of general market trends). In fact, LBMPs in the DAM never exceeded $100/MWh in either the Western NY or Hudson River superzones, while there were a few hours in which the RTM LBMPs spiked in excess of $250/MWh. The estimated supply models for Western NY and Hudson as well as the Day-Ahead and Real-Time Markets are displayed in Table 5-3 - Table 5-6, respectively. Consistent with previous year’s analyses, the models explain the day-ahead market rather well (i.e. r-squared in excess of 85%) but are not quite as capable at explaining the more variable real-time market. Shifter variables clearly help the models capture more of the variability, as evidenced by the significant t-ratios, than if these variables were not included. Based on these estimated supply curves, the average, minimum and maximum of the estimated supply flexibilities, defined as the percentage change in LBMP resulting from a one percent change in load served, for this time period are collected in Table 5-7 and reflect this lack of price variability. In the West, the average supply flexibility in the DAM was 0.18, with a very small range about the mean (-0.21 to 0.57). With more volatility in the RTM, the mean supply flexibility was substantially higher, in relative terms, at 5.10 with a range of –1.74 to 14.54 in the uppermost part of the supply curve. The Hudson River superzone experienced comparable results: average supply flexibilities were 0.09 in the DAM and 2.39 in the steepest part of the RTM supply curve with ranges from 0.05 to 0.11 and 0.74 to 7.20 in the DAM and RTM, respectively.

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	3.6929	56.8419		
Load	0.9730	10.6380		
Temperature Heat Index	0.0061	1.5430		
Max Previous Day THI	-0.0080	-2.2609		
Avg. Previous 3 Day THI	-0.0124	-6.5532		
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP				
Arch (0)	0.0010	20.76		
Arch (1)	0.3467	6.67		
Arch (2)	0.0408	2.11		
R^2 =	0.9314			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	-0.21			
Maximum	0.57			
Mean	0.18			

	Intercept	
	Coefficient	T-Ratio
	0.0017	1.6573
	-0.0028	-3.3350
	-0.0013	-2.1716
	-0.7661	-10.4830
Pk Sin	-0.0079	-0.3260
Pk Cos	-0.0109	-0.4985
Tues	0.0071	1.8027
Wed	-0.0045	-0.9200
Thurs	-0.0115	-2.3692
Fri	-0.0327	-11.0884

	Coefficient	T-Ratio
AR1	-0.7051	-18.2305
AR2	-0.0678	-1.3549
AR3	-0.0966	-2.1950
AR4	0.0372	0.8515
AR5	0.0024	0.0676
AR6	0.0403	1.3893
AR7	-0.0712	-2.4365
AR8	-0.6751	-23.7323
AR9	0.5186	13.6487
AR10	0.1313	2.7472
AR11	0.0711	1.6751
AR12	-0.0299	-0.6825
AR13	-0.0142	-0.3815
AR14	0.0036	0.1021
AR15	-0.0279	-0.8856
AR16	-0.1158	-4.3329

Table 5-3 Estimated Day-Ahead Market Supply Function, Western NY Superzone, Fall/Spring (9/03 – 11/03, 3/04 – 5/04)

Model Coefficients	The Segments of the "Spline" Supply Function: Segment 1 Coefficient	Segment 1 T-Ratio	Segment 2 Coefficient	Segment 2 T-Ratio
Constant	-181.0742	-11.3831		
Load	14.7098	3.1182	20.9583	11.7362
Temperature Heat Index				
Max Previous Day THI	-0.0411	-3.3951	-0.2635	-8.5430
Avg. Previous 3 Day THI			0.0004	2.4021
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error	0.0069	3.2554	0.0001	2.9632
DAM Coverage	-9.7264	-2.0818	-0.1657	-2.9482
Log of Generation/ICAP				
Arch (0)	0.0088	9.71		
Arch (1)	0.5969	8.85		
Arch (2)	0.2447	6.66		
Arch (3)	0.2229	5.17		
R^2 =	0.3491			
	Knots (% of Maximum Load)			
Price Flexibilities**	80.0%		100.0%	
Minimum	0.67		-1.74	
Maximum	4.36		14.54	
Mean	2.59		5.10	

	Intercept Coefficient	Intercept T-Ratio
Max Previous Day THI	2.3436	8.5294
Pk Sin	0.0091	0.7994
Pk Cos	-0.0075	-0.7232
Tues	0.0026	0.1183
Wed	-0.0890	-4.1577
Thurs	0.0250	1.2152
Fri	0.0218	1.0563

	Coefficient	T-Ratio
AR1	-0.3874	-9.4843
AR2	-0.1188	-3.0723
AR3	-0.0749	-1.9331
AR4	0.1036	3.0715
AR5	-0.1358	-4.8639
AR6	-0.0068	-0.2867
AR7	-0.1232	-4.7389
AR8	-0.0018	-0.0667
AR9	-0.0033	-0.1253
AR10	-0.0017	-0.0613
AR11	0.0176	0.7094
AR12	-0.0398	-1.5645
AR13	-0.0045	-0.1993
AR14	-0.0433	-1.7121
AR15	-0.0931	-4.3002
AR16	-0.0169	-0.8149

Table 5-4 Estimated Real-Time Market Supply Function, Western NY Superzone, Fall/Spring (9/03 – 11/03, 3/04 – 5/04)

Model Coefficients	The Segments of the "Spline" Supply Function: Segment 1 Coefficient	Segment 1 T-Ratio	Segment 2 Coefficient	Segment 2 T-Ratio
Constant	3.7402	109.9133		
Load	0.0158	0.7957		
Temperature Heat Index				
Max Previous Day THI	0.0011	3.8104		
Avg. Previous 3 Day THI				
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP				
Arch (0)	0.0008	11.41		
Arch (1)	0.5300	6.74		
Arch (2)	0.2860	4.85		
R^2 =	0.8568			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	0.05			
Maximum	0.11			
Mean	0.09			

	Intercept Coefficient	Intercept T-Ratio
Avg. Previous 3 Day THI	0.0012	3.7047
Wgt. Transmission Outages	0.0000	2.4174
Wgt. Transmission Constraints	0.0298	5.1870
Log of Generation/ICAP	-0.5718	-6.3853
Pk Sin	0.0201	2.2774
Pk Cos	-0.0331	-4.1463
Tues	-0.0018	-0.4886
Wed	-0.0086	-2.1362
Thurs	0.0053	1.3558
Fri	-0.0123	-3.6186

	Coefficient	T-Ratio
AR1	-0.3381	-12.4718
AR2	0.0503	1.3534
AR3	-0.0213	-0.6436
AR4	-0.0089	-0.2982
AR5	0.0112	0.4369
AR6	0.0206	1.1860
AR7	-0.0724	-4.4954
AR8	-0.6276	-36.5041
AR9		
AR10		
AR11		
AR12		
AR13		
AR14		
AR15		
AR16		

Table 5-5 Estimated Day-Ahead Market Supply Function, Hudson River Superzone, Fall/Spring (9/03 – 11/03, 3/04 – 5/04)

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	-82.8291	-2.9881		
Load	7.1942	3.7639	10.5101	3.1448
Temperature Heat Index				
Max Previous Day THI			-0.1123	-2.5225
Avg. Previous 3 Day THI			0.0005	4.1550
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error			0.0001	4.6425
DAM Coverage	-5.5970	-2.7900	-0.1355	-3.3185
Log of Generation/ICAP			-0.1533	-5.7895
Arch (0)	0.0076	9.18		
Arch (1)	0.7586	10.05		
Arch (2)	0.5289	8.94		
Arch (3)	0.1227	3.05		
R^2 =	0.4235			
	Knots (% of Maximum Load)			
Price Flexibilities**	70.0%		100.0%	
Minimum	0.88		0.74	
Maximum	2.37		7.20	
Mean	1.80		2.39	

	Intercept	
	Coefficient	T-Ratio
	0.9342	2.5253
Pk Sin	-0.0228	-2.5510
Pk Cos	0.0092	1.2716
Tues	-0.0105	-0.6127
Wed	-0.0384	-1.9428
Thurs	-0.0062	-0.3094
Fri	-0.0511	-2.7758

	Coefficient	T-Ratio
AR1	-0.4386	-12.2257
AR2	0.0182	0.5050
AR3	-0.0765	-2.6876
AR4	-0.0066	-0.3072
AR5	-0.1321	-6.1728
AR6	0.0877	4.3782
AR7	-0.1168	-5.5673
AR8	-0.0265	-1.3599
AR9	-0.0286	-1.2764
AR10	0.0227	1.1622
AR11	0.0247	1.1743
AR12	-0.0402	-2.0826
AR13	0.0668	3.5923
AR14	-0.0602	-3.6002
AR15	-0.0213	-1.0523
AR16	0.0245	1.3610

Table 5-6 Estimated Real-Time Market Supply Function, Hudson River Superzone, Fall/Spring (9/03 – 11/03, 3/04 – 5/04)

Western NY Superzone

		Supply Flexibility Estimates		
Market	Part of Spline	Min	Avg.	Max
DAM	1 of 1	-0.21	0.18	0.57
RTM	1 of 2	0.67	2.59	4.36
RTM	2 of 2	-1.74	5.10	14.54

Hudson River Superzone

		Supply Flexibility Estimates		
Market	Part of Spline	Min	Avg.	Max
DAM	1 of 1	0.05	0.09	0.11
RTM	1 of 2	0.88	1.80	2.37
RTM	2 of 2	0.74	2.39	7.20

Table 5-7 Estimated Supply Flexibilities for Spring/Fall ((9/03 – 11/03, 3/04 – 5/04)

Because of the observed low prices that caused these supply flexibilities to remain low, opportunities for DADRP bids to be scheduled were slim and the consequent effect on markets was expected to be slight. According to Table 5-8, there were 415 DADRP bids scheduled by the NYISO over this 6-month fall/spring period, with all but 4 submitted by participants in the Hudson River superzone (i.e. NYISO zones F – I). This amounted to 1,384 MWHs of scheduled demand response.

Superzone	Sch. Bids	Sch. MWh	DAM Collateral Savings	RTM Collateral Savings	Reduction in Hedge Costs	Total Impacts	Program Payments	Change in NSW
Hudson River	411	1,375	$3,347	$4,544	$14,631	$22,522	$75,718	-$63,519
Western NY	4	9	$29	-$14	$3,979	$3,993	$476	-$566
Total	415	1,384	$3,376	$4,530	$18,609	$26,515	$76,194	-$64,085

Table 5-8 DADRP Market Impacts for Spring/Fall (9/03 – 11/03, 3/04 – 5/04)

Following the methodology developed for previous evaluations, the estimation of market impacts is based on the reduction in the market-clearing price for electricity due to the scheduled load curtailments through DADRP. Such reduction in demand not only affect consumers in the Day-Ahead Market, but will also cause spot market LBMPs to be reduced from what it otherwise would have been, provided the demand reduction is successful. In addition, the reduction in LBMP in the DAM could cause a reduction in the cost of hedging load if both parties entering a hedge contract expect these lower prices to be maintained. Finally, load curtailments bid in by end-use customers on a flat-rate tariff increase social welfare by allowing society to better allocate resources to their ”best” uses.

Table 5-8 further provides the estimates of the market effects. For the Hudson River superzone, the DAM collateral savings are $3,347, RTM collateral savings are $4,544, hedging savings are $14,631, providing a total impact of $22,522. These reductions were undertaken in exchange for payments totaling $75,718, yielding an impact ratio of 0.30. In Western NY, the DAM collateral savings are $29, RTM collateral savings of $-14 (due to LSEs in this superzone holding a long position in the RTM), hedging savings of $3,979, to produce a total impact of $3,993. Such benefits were achieved through payments to participants of $476, resulting in an impact ratio of 8.4. The net change in social welfare was large in the Hudson Region, -$63,519, due to the large number of bids scheduled during hours with a very low supply flexibility, and was small but still negative in Western NY (-$566) for much the same reasons.

During the winter months, average peak period DAM prices were higher by $6/MWh than they were in the fall/spring time period but showed lower maximum prices (see Appendix A - Market Trends). This difference in the price series produced different estimated supply models for the winter months, as displayed in Table 5-9 – Table 5-12 for the two modeled areas and NYISO markets. Due to the lower variability in prices, the supply models were able to explain over 92% of the variation in the DAM and over 56% in the RTM. According to Table 5-13, a summary of the estimated price flexibilities derived from the supply models, Western NY had an average supply flexibility of 0.45 in the DAM, with values ranging from a low of 0.10 to a high of 0.75. Once again, the RTM experienced more price volatility than the DAM, resulting in higher RTM estimates. The average supply flexibility in the RTM was 5.28 in the steepest part of the supply curve, where it ranged between 5.26 and 5.29. Similarly, the Hudson River superzone experienced an average of 0.18 with a range of 0.05 to 0.27 in the DAM, and an average of 2.54 in the RTM with a minimum of 0.81 and a maximum of 3.87.

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	4.5006	95.8543		
Load	-0.4324	-1.3193		
Temperature Heat Index				
Max Previous Day THI	-0.0090	-2.3361		
Avg. Previous 3 Day THI	0.0205	3.3541		
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP	-2.9410	-2.9454		
Arch (0)	0.0016	6.90		
Arch (1)	0.1956	2.67		
Arch (2)	0.6604	5.69		
R^2 =	0.9446			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	0.10			
Maximum	0.75			
Mean	0.45			

	Intercept	
	Coefficient	T-Ratio
Max Previous Day THI	-0.0060	-7.2663
Avg. Previous 3 Day THI	-0.0081	-5.8908
Pk Sin	0.1472	12.3630
Pk Cos	-0.0359	-2.8435
Tues	-0.0345	-3.5906
Wed	-0.0369	-2.6189
Thurs	-0.0422	-2.8602
Fri	-0.0348	-3.2252

	Coefficient	T-Ratio
AR1	-0.6631	-12.9093
AR2	0.0012	0.0165
AR3	-0.1341	-2.2014
AR4	-0.0161	-0.3394
AR5	-0.0341	-0.7232
AR6	0.0841	2.2559
AR7	-0.0688	-1.4637
AR8	-0.4378	-9.8254
AR9	0.3149	6.4471
AR10	0.1820	2.9843
AR11	-0.0633	-1.1248
AR12	0.1276	2.2939
AR13	-0.0095	-0.1917
AR14	0.1071	2.9168
AR15	-0.0927	-1.9648
AR16	-0.1645	-4.2028

Table 5-9 Estimated Day-Ahead Market Supply Function, Western NY Superzone, Winter (12/03 - 2/04)

	The Segments of the "Spline" Supply Function				Intercept	
	Segment 1		Segment 2			
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	-43.2250	-8.8934				
Load	3.9217	15.9222	5.2604	9.7660		
Temperature Heat Index						
Max Previous Day THI						
Avg. Previous 3 Day THI			-0.0008	-4.5891		
Wgt. Transmission Outages						
Wgt. Transmission Constraints						
Positive Forcast Error						
Negative Forcast Error	0.0048	3.0151				
DAM Coverage						
Log of Generation/ICAP			-0.1000	-3.2428		
Arch (0)	0.0107	4.93				
Arch (1)	0.9536	7.73				
Arch (2)	0.3810	4.63				
R^2 =	0.5771					
	Knots (% of Maximum Load)					
Price Flexibilities**	70.0%		100.0%			
Minimum	2.53		5.26			
Maximum	3.92		5.29			
Mean	3.46		5.28			

	Coefficient	T-Ratio
Pk Sin	-0.0127	-1.0006
Pk Cos	0.0017	0.1477
Tues	-0.0272	-0.9453
Wed	-0.0357	-1.0980
Thurs	-0.0440	-1.4329
Fri	0.0483	1.8014

	Coefficient	T-Ratio
AR1	-0.2167	-4.4463
AR2	-0.1069	-2.4697
AR3	-0.0275	-0.7004
AR4	-0.0105	-0.3804
AR5	0.0523	2.3172
AR6	-0.0242	-1.1904
AR7	0.0376	1.5340
AR8	-0.0137	-0.4433
AR9	-0.0060	-0.1875
AR10	-0.0114	-0.3168
AR11	-0.0101	-0.3483
AR12	-0.0171	-0.6827
AR13	0.0924	3.2996
AR14	-0.0613	-2.5688
AR15	0.0690	2.3197
AR16	0.0259	0.9001

Table 5-10 Estimated Real-Time Market Supply Function, Western NY Superzone, Winter (12/03 - 2/04)

	The Segments of the "Spline" Supply Function				Intercept	
	Segment 1		Segment 2			
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	4.7697	126.1292				
Load	-0.1027	-1.0836				
Temperature Heat Index	0.0024	1.7369				
Max Previous Day THI					-0.0055	-7.9607
Avg. Previous 3 Day THI					-0.0126	-13.0092
Wgt. Transmission Outages						
Wgt. Transmission Constraints						
Positive Forcast Error						
Negative Forcast Error						
DAM Coverage						
Log of Generation/ICAP	-0.9758	-2.6823				
Arch (0)	0.0013	6.69				
Arch (1)	0.2045	3.73				
Arch (2)	1.0014	7.27				
R^2 =	0.9298					
	Knots (% of Maximum Load)					
Price Flexibilities**	100.0%		100.0%			
Minimum	0.05					
Maximum	0.27					
Mean	0.18					

	Coefficient	T-Ratio
Pk Sin	0.1088	7.2622
Pk Cos	-0.0498	-4.7970
Tues	-0.0256	-2.4955
Wed	-0.0228	-1.6961
Thurs	-0.0052	-0.3648
Fri	-0.0089	-0.8301

	Coefficient	T-Ratio
AR1	-0.6146	-13.6616
AR2	0.0387	0.5778
AR3	-0.1413	-2.6172
AR4	0.0352	0.7580
AR5	-0.0739	-1.8210
AR6	0.1184	5.2985
AR7	-0.0609	-1.5405
AR8	-0.5035	-13.5846
AR9	0.3067	7.2285
AR10	0.1279	2.4116
AR11	0.0032	0.0735
AR12	0.0632	1.6819
AR13	0.0417	0.9615
AR14	0.0569	1.9851
AR15	-0.0886	-2.5414
AR16	-0.0528	-1.8696

Table 5-11 Estimated Day-Ahead Market Supply Function, Hudson River Superzone, Winter (12/03 - 2/04)

	The Segments of the "Spline" Supply Function									
	Segment 1		Segment 2			Intercept				
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio		Coefficient	T-Ratio		Coefficient	T-Ratio
Constant	4.9506	45.6214								
Load	3.2264	5.2207								
Temperature Heat Index								AR1	-0.2376	-4.6165
Max Previous Day THI	-0.0646	-4.7170				-0.0142	-5.1066	AR2	-0.0825	-2.1739
Avg. Previous 3 Day THI	0.0745	5.0986				0.0133	3.2946	AR3	-0.0805	-2.1241
Wgt. Transmission Outages								AR4	-0.0418	-1.3438
Wgt. Transmission Constraints								AR5	0.0759	2.6992
Positive Forcast Error	-0.0011	-2.7261				-0.0003	-2.4934	AR6	-0.0237	-0.9375
Negative Forcast Error								AR7	0.0020	0.0813
DAM Coverage								AR8	-0.0629	-2.2266
Log of Generation/ICAP								AR9	0.0263	0.7958
								AR10	-0.0259	-0.9217
Arch (0)	0.0129	5.53			Pk Sin	-0.0540	-2.7244	AR11	-0.0139	-0.3921
Arch (1)	1.0130	7.35			Pk Cos	-0.0113	-0.7213	AR12	-0.0166	-0.5407
Arch (2)	0.2147	3.89			Tues	-0.1221	-4.2752	AR13	0.0601	1.7845
R^2 =	0.5602				Wed	-0.0594	-1.6878	AR14	-0.0346	-1.4359
	Knots (% of Maximum Load)				Thurs	-0.0154	-0.4629	AR15	0.0255	1.1388
Price Flexibilities**	100.0%		100.0%		Fri	0.0173	0.5007	AR16	-0.0237	-0.8242
Minimum	0.81									
Maximum	3.87									
Mean	2.54									

Table 5-12 Estimated Real-Time Market Supply Function, Hudson River Superzone, Winter (12/03 - 2/04)

Western NY Superzone

		Supply Flexibility Estimates		
Market	Part of Spline	Min	Avg.	Max
DAM	1 of 1	0.10	0.45	0.75
RTM	1 of 2	2.53	3.46	3.92
RTM	2 of 2	5.26	5.28	5.29

Hudson River Superzone

		Supply Flexibility Estimates		
Market	Part of Spline	Min	Avg.	Max
DAM	1 of 1	0.05	0.18	0.27
RTM	1 of 1	0.81	2.54	3.87

Table 5-13 Estimated Supply Flexibilities for Winter (12/03 – 2/04)

As indicated in Table 5-14, there were more scheduled bids in the winter than there were in the much longer fall/spring season, but the distribution of bids was comparable with most coming from the Hudson River superzone. In this area, the DAM collateral savings are $7,126, RTM collateral savings are $2,373, hedging savings are $11,990, for a total impact of $21,489. These were accomplished by paying customers for curtailments costing $82,229. In the Western NY superzone, the DAM collateral savings are $1,882, RTM collateral savings are $-22 (due to LSEs in this superzone holding a long position in the RTM), hedge savings of $22,023, for a total impact of $23,883. Such benefits were achieved through payments to program participants equaling $10,550. The Hudson River superzone would therefore have an impact ratio of 0.26 whereas the Western NY superzone would have an impact ratio of just over 2.2. Due to the slightly higher flexibilities and few bids accepted in Western NY, the change in net social welfare benefits was only -$56,808. However, in the Capital area, with more load curtailments scheduled during the winter at low points on the supply curve, the change in net social welfare was bigger (in an absolute sense) than in the spring/fall season (-$9,778 vs. -$566).

Superzone	Sch. Bids	Sch. MWh	DAM Collateral Savings	RTM Collateral Savings	Reduction in Hedge Costs	Total Impacts	Program Payments	Change in NSW
Hudson River	559	1,296	$7,126	$2,373	$11,990	$21,489	$82,229	-$56,808
Western NY	28	180	$1,882	-$22	$22,023	$23,883	$10,550	-$9,779
Total	587	1,476	$9,008	$2,351	$34,013	$45,373	$92,779	-$66,587

Table 5-14 DADRP Market Impacts for Winter (12/03 – 2/04)

Summer is traditionally the highest priced period of the year, but in 2004 such was not the case. Although LBMPs in the June, July and August DAM and RTM for Western NY and the Hudson Valley superzone were roughly the same or slightly above those observed on average in the winter, the maximum observed prices were close to $30 to $40/MWh less (see Appendix A - Market Trends). Such a reduced level of prices resulted in the estimated supply models, presented in Table 5-15 – Table 5-22, producing generally low estimates of the supply flexibilities. The average supply flexibility in the Western NY superzone was 1.84 for the steepest part of the DAM supply curve, with no variation to speak of, but ranged between 0.07 and 0.75 in the lower part of the curve, as summarized in Table 5-23. In the Hudson River superzone, the average supply flexibility was 1.60 in the highest part of the curve, with only minimal change between 1.59 and 1.62. As in the other time periods, the RTM displayed slightly higher prices and price volatility leading to larger estimates of the supply price flexibility in both zones. The Western NY superzone experienced a much tighter range value over other time periods in this analysis of 1.26 to 3.21, with an average value of 2.28. As for the Hudson River superzone, the supply flexibility was estimated to be between 0.27 and 2.08, averaging out at 1.23 for the real-time market.

Model Coefficients	The Segments of the "Spline" Supply Function: Segment 1 Coefficient	Segment 1 T-Ratio	Segment 2 Coefficient	Segment 2 T-Ratio
Constant	-12.7926	-4.4421		
Load	-1.3214	-4.9483	1.8299	5.6044
Temperature Heat Index	0.0237	6.3346		
Max Previous Day THI				
Avg. Previous 3 Day THI				
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP			-0.0535	-2.6917
Arch (0)	0.0012	13.91		
Arch (1)	0.0805	1.53		
Arch (2)				
R^2 =	0.8877			
	Knots (% of Maximum Load)			
Price Flexibilities**	77.0%		100.0%	
Minimum	0.07		1.84	
Maximum	0.75		1.84	
Mean	0.43		1.84	

	Intercept: Coefficient	T-Ratio
Max Previous Day THI	0.0069	11.7153
Avg. Previous 3 Day THI	0.0015	1.9870
Pk Sin	-0.0077	-1.8426
Pk Cos	0.0503	13.2169
Tues	-0.0097	-1.4873
Wed	-0.0195	-2.4340
Thurs	-0.0324	-4.0039
Fri	-0.0383	-6.0228

	Coefficient	T-Ratio
AR1	-0.7391	-13.1896
AR2	-0.0486	-0.7116
AR3	0.0059	0.0910
AR4	-0.0919	-1.3744
AR5	0.0201	0.2939
AR6	0.1048	1.5263
AR7	-0.1405	-2.4275
AR8	-0.1968	-4.1343
AR9	0.2262	4.0243
AR10	-0.0177	-0.2549
AR11	0.0007	0.0113
AR12	-0.0591	-0.9010
AR13	-0.0066	-0.0987
AR14	-0.0128	-0.1874
AR15	0.1022	1.8295
AR16	-0.1057	-2.2572

Table 5-15 Estimated Day-Ahead Market Supply Function, Western NY Superzone, Summer (6/04 – 8/04)

Model Coefficients	The Segments of the "Spline" Supply Function: Segment 1 Coefficient	Segment 1 T-Ratio	Segment 2 Coefficient	Segment 2 T-Ratio
Constant	3.1548	8.3826		
Load	-2.6495	-1.4101		
Temperature Heat Index	0.0667	2.6376		
Max Previous Day THI				
Avg. Previous 3 Day THI				
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP				
Arch (0)	0.0104	4.84		
Arch (1)	0.5534	4.12		
Arch (2)	0.2658	1.78		
R^2 =	0.4224			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	1.26			
Maximum	3.21			
Mean	2.28			

	Intercept: Coefficient	T-Ratio
Temperature Heat Index	0.0166	3.4204
Positive Forcast Error	-0.0001	-2.4475
Pk Sin	0.0120	0.8033
Pk Cos	-0.0121	-0.9153
Tues	-0.0340	-1.1066
Wed	-0.1169	-3.1307
Thurs	-0.0288	-0.7742
Fri	-0.0500	-1.4549

	Coefficient	T-Ratio
AR1	-0.5819	-8.4199
AR2	0.0218	0.2847
AR3	-0.0103	-0.1782
AR4	-0.1000	-1.8703
AR5	-0.1070	-1.9777
AR6	0.0049	0.0757
AR7	-0.1181	-2.1939
AR8	0.0317	0.5291
AR9	-0.0787	-1.5464
AR10	-0.0431	-0.8494
AR11	0.0404	0.7909
AR12	0.0003	0.0051
AR13	0.0044	0.0932
AR14	-0.0097	-0.1998
AR15	0.0505	0.9930
AR16	0.0073	0.1599

Table 5-16 Estimated Real-Time Market Supply Function, Western NY Superzone, Summer (6/04 – 8/04)

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	-9.3000	-6.5559		
Load	-2.4661	-6.6090	1.4454	8.3962
Temperature Heat Index				
Max Previous Day THI	0.0167	5.8136	0.0010	9.0704
Avg. Previous 3 Day THI	0.0135	3.8788	0.0006	4.4261
Wgt. Transmission Outages				
Wgt. Transmission Constraints				
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP	-1.5016	-2.2194	-0.1961	-6.5393
Arch (0)	0.0009	11.17		
Arch (1)	0.6677	6.68		
Arch (2)				
R^2 =	0.8390			
	Knots (% of Maximum Load)			
Price Flexibilities**	80.0%		100.0%	
Minimum	-0.17		1.59	
Maximum	0.49		1.62	
Mean	0.14		1.60	

	Intercept	
	Coefficient	T-Ratio
	0.0163	3.8045
Pk Sin	-0.0098	-3.3687
Pk Cos	0.0527	17.3623
Tues	-0.0079	-0.9239
Wed	0.0191	2.1995
Thurs	-0.0038	-0.4240
Fri	-0.0207	-3.0099

	Coefficient	T-Ratio
AR1	-0.5782	-12.0851
AR2	-0.0693	-1.2244
AR3	-0.1105	-1.9007
AR4	0.0290	0.5549
AR5	0.0065	0.1484
AR6	0.0569	1.3014
AR7	-0.0072	-0.1844
AR8	-0.2573	-7.7239
AR9	0.2573	5.7327
AR10	-0.0142	-0.2738
AR11	0.0422	0.8101
AR12	-0.1819	-3.5830
AR13	0.0888	2.0036
AR14	0.0811	1.6786
AR15	0.1859	4.4580
AR16	-0.2272	-7.2070

Table 5-17 Estimated Day-Ahead Market Supply Function, Hudson River Superzone, Summer (6/04 – 8/04)

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	5.6806	12.1698		
Load	3.8525	2.8296		
Temperature Heat Index				
Max Previous Day THI				
Avg. Previous 3 Day THI	0.0158	2.2196		
Wgt. Transmission Outages	0.0001	1.5236		
Wgt. Transmission Constraints				
Positive Forcast Error	-0.0002	-1.6638		
Negative Forcast Error				
DAM Coverage	-3.9291	-2.9571		
Log of Generation/ICAP				
Arch (0)	0.0045	3.79		
Arch (1)	0.3479	4.80		
Arch (2)				
R^2 =	0.6398			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	0.27			
Maximum	2.08			
Mean	1.23			

	Intercept	
	Coefficient	T-Ratio
	-1.5239	-3.0623
	-0.8340	-2.2125
Pk Sin	-0.0446	-4.9288
Pk Cos	0.0294	3.0478
Tues	-0.0174	-0.6414
Wed	-0.0105	-0.2923
Thurs	-0.0097	-0.2943
Fri	-0.0303	-1.1327

	Coefficient	T-Ratio
AR1	-0.5368	-10.3789
AR2	0.0100	0.1786
AR3	-0.1484	-2.6034
AR4	0.0902	1.6838
AR5	-0.1577	-3.0329
AR6	0.0830	1.6234
AR7	0.0618	1.2856
AR8	-0.0831	-1.8142
AR9	0.0029	0.0636
AR10	-0.0029	-0.0618
AR11	-0.0212	-0.4133
AR12	0.0148	0.2847
AR13	0.0161	0.2961
AR14	0.0769	1.5503
AR15	0.0432	0.9936
AR16	-0.0537	-1.3880

Table 5-18 Estimated Real-Time Market Supply Function, Hudson River Superzone, Summer (6/04 – 8/04)

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	3.0724	18.0977		
Load	-3.3620	-4.4592		
Temperature Heat Index				
Max Previous Day THI	0.0384	4.5390		
Avg. Previous 3 Day THI				
Wgt. Transmission Outages	0.0001	2.0268		
Wgt. Transmission Constraints	0.1036	1.6072		
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP	-6.0147	-3.5847		
Arch (0)	0.0019	16.73		
Arch (1)	0.1213	2.09		
Arch (2)				
R2 =	0.8810			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	-0.04			
Maximum	1.49			
Mean	0.68			

	Intercept	
	Coefficient	T-Ratio
Temperature Heat Index	0.0017	2.5456
Max Previous Day THI	0.0113	6.2707
Log of Generation/ICAP	-2.4199	-5.6171
Pk Sin	0.0058	1.3104
Pk Cos	0.0376	8.2700
Tues	0.0151	1.0413
Wed	0.0446	3.1605
Thurs	0.0222	1.7305
Fri	-0.0248	-2.7910

	Coefficient	T-Ratio
AR1	-0.7850	-13.0762
AR2	-0.1198	-1.7271
AR3	0.0104	0.1660
AR4	-0.0321	-0.4755
AR5	0.0780	1.0913
AR6	-0.0224	-0.3159
AR7	0.0423	0.7567
AR8	-0.1326	-2.3024
AR9	0.0713	1.2646
AR10	0.1274	2.1978
AR11	-0.0953	-1.5937
AR12	-0.1100	-1.5665
AR13	0.0255	0.3341
AR14	0.0256	0.3387
AR15	0.0011	0.0169
AR16	-0.0020	-0.0410

Table 5-19 Day-Ahead Market Supply Function, New York City, Summer (6/04 – 8/04)

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	-11.9839	-1.9541		
Load	-4.4884	-3.1605	1.7806	2.6054
Temperature Heat Index				
Max Previous Day THI	0.0605	3.4462	0.0015	4.2044
Avg. Previous 3 Day THI				
Wgt. Transmission Outages			0.0000	1.9345
Wgt. Transmission Constraints			0.0016	4.7889
Positive Forcast Error			0.0000	-2.3586
Negative Forcast Error				
DAM Coverage			-0.0953	-1.9538
Log of Generation/ICAP				
Arch (0)	0.0062	5.28		
Arch (1)	0.4541	5.94		
Arch (2)				
R^2 =	0.7611			
	Knots (% of Maximum Load)			
Price Flexibilities**	80.0%		100.0%	
Minimum	-0.56		1.80	
Maximum	1.54		1.85	
Mean	0.39		1.82	

	Intercept	
	Coefficient	T-Ratio
Pk Sin	0.0196	1.5119
Pk Cos	0.0422	3.6256
Tues	-0.0251	-1.0108
Wed	-0.0871	-2.4967
Thurs	-0.0938	-3.1334
Fri	-0.0787	-3.1331

	Coefficient	T-Ratio
AR1	-0.6811	-12.0738
AR2	0.0667	0.9920
AR3	-0.0457	-0.7025
AR4	0.0147	0.2677
AR5	-0.0274	-0.4776
AR6	-0.0127	-0.2345
AR7	-0.0346	-0.6696
AR8	0.0558	1.1672
AR9	-0.0647	-1.3980
AR10	-0.0113	-0.2085
AR11	-0.0279	-0.5596
AR12	0.0690	1.4140
AR13	0.0098	0.1897
AR14	0.0168	0.3231
AR15	-0.0296	-0.6039
AR16	0.0306	0.7680

Table 5-20 Estimated Real-Time Market Supply Function, New York City, Summer (6/04 – 8/04)

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	3.3141	27.9123		
Load	-2.6214	-5.7280		
Temperature Heat Index				
Max Previous Day THI	0.0381	6.9848		
Avg. Previous 3 Day THI				
Wgt. Transmission Outages	0.0003	3.6973		
Wgt. Transmission Constraints	0.1859	5.2949		
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP				
Arch (0)	0.0008	10.03		
Arch (1)	0.7740	5.41		
Arch (2)				
R^2 =	0.8643			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	-0.14			
Maximum	1.27			
Mean	0.58			

	Intercept	
	Coefficient	T-Ratio
Temperature Heat Index	0.0017	2.6414
Max Previous Day THI	0.0101	6.9784
Wgt. Transmission Outages	0.0001	3.9764
Log of Generation/ICAP	-0.8585	-4.2046
Pk Sin	0.0060	1.6703
Pk Cos	0.0384	12.3848
Tues	0.0272	4.5576
Wed	0.0162	1.7595
Thurs	-0.0092	-0.8860
Fri	-0.0128	-1.6838

	Coefficient	T-Ratio
AR1	-0.7105	-13.6176
AR2	-0.1212	-2.1003
AR3	-0.0532	-1.0125
AR4	-0.0104	-0.2295
AR5	0.0471	1.1296
AR6	0.1259	3.0496
AR7	-0.1207	-3.1274
AR8	-0.2015	-4.9212
AR9	0.2143	5.0555
AR10	0.0170	0.3854
AR11	-0.0549	-1.0618
AR12	-0.0013	-0.0242
AR13	-0.0136	-0.3396
AR14	-0.0007	-0.0146
AR15	0.0019	0.0480
AR16	-0.0211	-0.5943

Table 5-21 Estimated Day-Ahead Market Supply Function, Long Island, Summer (6/04 – 8/04)

	The Segments of the "Spline" Supply Function			
	Segment 1		Segment 2	
Model Coefficients	Coefficient	T-Ratio	Coefficient	T-Ratio
Constant	3.3141	27.9123		
Load	-2.6214	-5.7280		
Temperature Heat Index				
Max Previous Day THI	0.0381	6.9848		
Avg. Previous 3 Day THI				
Wgt. Transmission Outages	0.0003	3.6973		
Wgt. Transmission Constraints	0.1859	5.2949		
Positive Forcast Error				
Negative Forcast Error				
DAM Coverage				
Log of Generation/ICAP				
Arch (0)	0.0008	10.03		
Arch (1)	0.7740	5.41		
Arch (2)				
R^2 =	0.8643			
	Knots (% of Maximum Load)			
Price Flexibilities**	100.0%		100.0%	
Minimum	-0.14			
Maximum	1.27			
Mean	0.58			

	Intercept	
	Coefficient	T-Ratio
Temperature Heat Index	0.0017	2.6414
Max Previous Day THI	0.0101	6.9784
Wgt. Transmission Outages	0.0001	3.9764
Log of Generation/ICAP	-0.8585	-4.2046
Pk Sin	0.0060	1.6703
Pk Cos	0.0384	12.3848
Tues	0.0272	4.5576
Wed	0.0162	1.7595
Thurs	-0.0092	-0.8860
Fri	-0.0128	-1.6838

	Coefficient	T-Ratio
AR1	-0.7105	-13.6176
AR2	-0.1212	-2.1003
AR3	-0.0532	-1.0125
AR4	-0.0104	-0.2295
AR5	0.0471	1.1296
AR6	0.1259	3.0496
AR7	-0.1207	-3.1274
AR8	-0.2015	-4.9212
AR9	0.2143	5.0555
AR10	0.0170	0.3854
AR11	-0.0549	-1.0618
AR12	-0.0013	-0.0242
AR13	-0.0136	-0.3396
AR14	-0.0007	-0.0146
AR15	0.0019	0.0480
AR16	-0.0211	-0.5943

Table 5-22 Estimated Real-Time Market Supply Function, Long Island, Summer (6/04 – 8/04)

Western NY Superzone

		Supply Flexibility Estimates		
Market	Part of Spline	Min	Avg.	Max
DAM	1 of 2	0.07	0.43	0.75
DAM	2 of 2	1.84	1.84	1.84
RTM	1 of 1	1.26	2.28	3.21

Hudson River Superzone

		Supply Flexibility Estimates		
Market	Part of Spline	Min	Avg.	Max
DAM	1 of 2	-0.17	0.14	0.49
DAM	2 of 2	1.59	1.60	1.62
RTM	1 of 1	0.27	1.23	2.08

Table 5-23 Estimated Supply Flexibilities for Summer (6/04 – 8/04)

According to Table 5-24, during the Summer of 2004 there were markedly fewer bids accepted than during any other 3 months period over the previous 12 months. The relatively mild summer, which resulted in low supply price flexibilities, may have restricted the number of opportunities for bids to be scheduled. When they were scheduled, they did not have a large effect on the market place. As reported in **Error! Reference source not found.**, the Collateral Savings in the DAM and RTM was $4,296 and $2,100, respectively for the Hudson River superzone and $2,385 and $214 respectively for the Western NY superzone. Interestingly, the reduction in hedge costs is almost identical ($18,798 and $17,142) for Hudson River and Western NY in spite of the significant differences in scheduled curtailments. This is most likely due to the hedge strategies utilized by utilities in the two respective regions of the NYCA and the hours in which the bids were accepted. These benefits are realized through payments totaling $34,507 in the West and $6,145 down the Hudson River, and would have resulted in an impact ratio of 3.4 and 0.7 in the two respective locales. Net social welfare benefits were again negative and large in the West (-$5,302) but much smaller (on absolute terms) in the Hudson region (-$22,106).

Superzone	Sch. Bids	Sch. MWh	DAM Collateral Savings	RTM Collateral Savings	Reduction in Hedge Costs	Total Impacts	Program Payments	Change in NSW
Hudson River	162	560	$4,296	$2,100	$18,798	$25,194	$34,507	-$22,106
Western NY	33	115	$2,385	$214	$18,142	$20,742	$6,145	-$5,302
Total	195	675	$6,682	$2,314	$36,940	$45,936	$40,651	-$27,408

Table 5-24 DADRP Market Impacts for Summer (6/04 – 8/04)

One possible explanation for the low impact ratio in the Hudson River superzone in all four seasons would be due to the hours the bids were scheduled. Although they passed the minimum $50/MWh bid threshold, the slope of the supply curve during these scheduled periods was so slight that such reductions had little impact on the market. In addition, many of these bids were submitted during times that would not directly affect the cost of a hedge and were therefore not included in the hedge savings calculations. Conversely, the relatively infrequent bidding behavior of DADRP participants in the Western NY superzone corresponded with times when hedge contracts would be affected and the supply curve was steep enough to generate an impact ratio in excess of 1.0.