Chapter 4 – Results from the PRL Program Evaluation

Now that some background data on the day-ahead and real time electricity markets have been discussed, and the evaluation methodology has been outlined, the remainder of the report focuses on the results of the evaluation. Efforts to characterize the effects on participation due to the 2003 program changes are presented in the section below. That section is followed by the evaluation of EDRP, and finally, the results from the DADRP evaluation are discussed.

Summary of PRL Program Changes

The year 2003 marks the third year in which customers could participate in the NYISO's EDRP and DADRP programs, and the fourth year for the ICAP/SCR program. During 2001 and 2002 customers (with the exception of those operating DG units) were able to participate in any single program or in any combination of the three programs.[1] Prior to the 2003 enrollment period, the NYISO implemented several important changes in the programs that could potentially change participation rates. They include:

- The imposition of $50/MWH price floor for DADRP bids;
- The elimination of a 10% penalty applied to curtailment imbalances in DADRP;
- The uncoupling of EDRP and ICAP/SCR, allowing customers to be enrolled in only one of the two programs at any point in time;
- The ability for dispatchers to deploy only a portion of ICAP/SCR curtailment capability, during an emergency event, where only some participants might be called to curtail load during an emergency event;
- To implement a partial dispatch, ICAP/SCR customers are required to nominate a strike price (capped at $500/MWH) at which they would be dispatched during events where not all-available curtailment capability was needed; and
- During ICAP/SCR curtailments, those called to curtail are eligible for an energy payment-- the higher of their nominated strike price or the prevailing LBMP.

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[1] Sequencing protocols determined under which program a joint participant was paid when a day-ahead DADRP scheduled curtailment became coincident with a same-day EDRP or ICAP/SCR event.

In addition, some changes in market operating protocols have implications for demand response program participation and performance. These changes include:

- When dispatched, ICAP/SCR and EDRP resources can now set LBMP during SCD intervals in which their reductions are needed to maintain required reserve levels.
- The ICAP reconfiguration auction created a more robust monthly spot market that was expected to raise the clearing prices for ICAP/SCR resources when sold into that auction.

This latter change in operating protocols might well be expected to make ICAP/SCR participation more attractive than EDRP. Further, by allowing these resources to set LBMP, the ICAP/SCR dispatch strike price (which could be as high as $500/MWH) or the EDRP price floor ($500/MWH) could effectively place a floor on the real-time LBMP during emergency events. This protocol could therefore lead to higher prices during those periods when EDRP and ICAP/SCR are dispatched than has been the case in previous years.

Efforts to Assess the Effects of Program Changes

Several working hypotheses help guide the assessment of how these 2003 program changes might affect program participation. They are outlined below.

The changes in DADRP are likely to have distinct and opposite affects:

- The elimination of the 10% penalty on DADRP imbalances would have a negligible impact on participation; and
- The imposition of a $50/MWH bid floor would act as a deterrent to DADRP participation.

The uncoupling and realignment of ICAP/SCR and EDRP are likely to have at least three distinct effects:

- The uncoupling of the programs may lead to the migration of EDRP participants to ICAP/SCR;
- The requirement that ICAP/SCR participants nominate a curtailment strike price may complicate recruitment and possibly act as deterrent to participation; and

- ICAP/SCR participant strike price nominations may well cluster around very low prices (near zero) and very high prices (close to the $500/MWH bid cap).

The uncoupling of the two programs is accommodated in conjunction with new dispatch rules (ICAP/SCR first and as needed) and the addition of energy payments for ICAP/SCR. For this reason, EDRP participants may migrate to ICAP/SCR because these additional provisions increase the benefit/risk ratio to ICAP/SCR participants. At the same time, the need for ICAP/SCR participants to nominate a strike price may reduce the attractiveness of the program, but for those remaining participants, one might expect low strike prices from customers confident in their ability to comply when asked to curtail. These customers might be somewhat eager to be asked to curtail so they can receive the energy payment. Alternatively, the cluster of high strike prices may be from some customers, content with the ICAP/SCR payment, attempting to limit their curtailment exposure.

To effect this evaluation, two separate initiatives were undertaken to generate information to test the above hypotheses. First, to characterize how the program changes affected recruiting efforts and program administration, a survey was administered to a small number of the entities that recruit customers to participation in the NYISO's demand response programs. These entities include regulated and competitive load serving entities (LSEs) and curtailment service providers. The survey was administered during the fall of 2003, so that this past summer's program history could be reflected in respondents' assessment of the programs' new provisions. The NYISO distributed the survey to everyone on the mailing list from its Price Responsive Load Working Group. The list includes entities that currently enroll participants in the NYISO's demand response programs, and direct serve and limited customers that represent themselves in the programs.

Second, to establish any patterns of retention or migration of customers between programs that might be attributable to the program changes, there was a detailed examination of the NYISO's program registration database to track the changes in program participation from previous years.

While no specific effort was made to sort out the separate effects of the general changes in dispatch protocol, some effects are implicit in the observed behavior of participants. In addition, because the only events called during 2003 are the ones immediately after the blackout, there is little that can be done to document the effect of these program changes on participations' behavior during the "typical" emergency events that had been experienced during 2001 and 2002.

The Survey Results

There are four major components to the survey. The results from each are described below.

The Survey Respondents

Of the 13 survey respondents, five are LSEs (two regulated and three competitive), six are demand response provider (DRPs), one is a retail customer, and one is an institutional respondent (Table 4.1). All but the institutional respondent and one competitive LSE recruited customers to participate in at least one of the NYISO demand response programs available in 2003. Most of them had done so in prior years. Some are also active in similar programs offered by the adjacent electricity markets, PJM Interconnection and ISO-NE.

As Chart 4.1 illustrates, most (10 of 13) enrolled customers in ICAP/SCR, and nearly half (6 of 13) sponsored customer participation in EDRP. Three respondents (one regulated LSE and two DRPs) actively promoted DADRP, but only two (one regulated LSE and one DRP) enrolled a customer in DADRP. Another two promoted DADRP only when the customer asked about participation. Seven of the respondents did not actively promote participation in DADRP (Chart 4.2).

These results generally square with previous evaluations of the DADRP program (Neenan Associates (2002) and Neenan Associates and CERTS (2003)), where awareness of DADRP was found to be low in general, and even low among those customers participating in ICAP/SCR or EDRP. Thus, it appears that LSEs and DRPs have concluded either that customers are not interested in DADRP, or that building such interest is not to their (the LSE's or DRP's) interest.

DADRP Experience

The five respondents that recruited customers to DADRP were also asked a number of questions regarding DADRP based on their experience. They were asked which customer groups were most receptive to learning about DADRP. Chart 4.3 illustrates the results, sorted by the response of the three DRPs and the two LSEs. All respondents agreed that some sectors (hospitals, colleges and secondary schools, light manufacturing, and restaurants) were unreceptive to DADRP participation. The two types of respondents disagreed, however, about the interest of other sectors. The DRPs reported that big box stores, wastewater treatment plants, and office buildings were relatively receptive, while the LSE's response indicates a perception of lower interest on the part of these customers.

Three of these five respondents reported that the removal of the 10% penalty for curtailment noncompliance created interest in DADRP, but did not lead to actual participation. The other two respondents thought that its removal had no influence. One possible interpretation of these results is that the penalty is perceived by some customers as being unduly severe, and its removal only highlights other features of the program that are seen as barriers to participation.[2]

In this regard, two of the respondents that actively marketing DADRP said the requirement that bids be submitted in one MW increments is the major barrier to customer participation in DADRP. The one MW bid increment requirement has been cited before as a deterrent to participation, because it forces the LSEs or DRPs to manage the risks if customers' bids do not meet that standard, or it forces customers to undertake the consequential market risk.

Two others said the major barrier to participation is the recently instituted $50/MWH bid floor. Objections to the bid floor have been voiced many times in NYISO Working Group meetings. The same objection has been raised about programs sponsored by PJM (which impose a slightly different but functionally similar price floor on bids).

Despite these responses, it is difficult to understand the reasons for this objection to the bid floor. Most customers already pay a commodity rate of at least $50/MWH; it is difficult to construct a situation where a customer would curtail at a DADRP price lower than what it pays for electricity use, except in cases where the customer can dispatch on-site generation with a

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[2] As part of previous evaluations, customers were asked about barriers to participation in DADRP. Few view the penalty as a barrier. More common responses were: that customers cannot curtail usage under the program circumstances, or even if they could curtail, the perceived benefits were not sufficient for them to do so.

lower fuel cost. Such actions, however, are not allowed under DADRP protocols. The one explanation favoring a lower (or no) bid floor is that some customers may want to bid curtailments coincident with planned partial or total facility shutdowns. This type of behavior is contrary to the DADRP objectives, one of which is to promote market efficiency by inducing curtailments that otherwise do not occur at times when such curtailments could lead to lower prices in the DAM price. A primary motivation for establishing the floor price is to forestall DADRP bidding during planned facility outages.

The active DADRP marketers were also asked to comment on four separate program changes in DADRP that might possibly boost program participation. None was enthusiastic about a provision whereby participants with scheduled bids would be paid for additional curtailments, beyond what was scheduled. Two thought that lowering the bid increment to 100 kW would increase participation, while two others thought that lowering the bid floor would do so as well. One respondent thought that settling scheduled curtailment shortfalls at the RTM LBMP, rather than the higher of RTM LBMP or the DAM LBMP at which the load reduction was scheduled, would be most helpful.[3]

The DADRP promoters were also asked if they preferred the current ‘incentivized’ DADRP to an ‘unincentivized’ alternative, and if DRPs not serving customers’ commodity needs should be authorized to promote participation in DADRP. Three of five prefer keeping the existing program, and all believe that DRPs should be part of the market structure, regardless of the specific features of DADRP. Finally, these five respondents were asked what they would do if there were no NYISO-sponsored DADRP program of any kind. The regulated LSEs said they would implement a Niagara Mohawk-type real-time pricing tariff indexed to DAM LBMPs. Two of the DRPs said they would offer some bidding opportunity; the third indicated that it would not offer any equivalent opportunity to participate in the NYISO spot market.[4]

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[3] On average, DAM prices are 3-5% higher than RTM LBMPs, which might appear to offer an arbitrage opportunity if participants could settle at the RTM LBMP. However, when prices are most volatile, RTM prices tend to be higher, thus foreclosing any opportunities for arbitrage. Perhaps the best argument for settling DADRP imbalances at the RTM LBMP is that it would further reduce deadweight losses that DADRP is intended to mitigate. More is said about this later in Chapter 4 in the section, The Market Effects of DADRP.

[4] The largest customers served by Niagara Mohawk are offered a POLR rate where the hourly energy prices

EDRP Experience

Seven of the provider survey respondents active in promoting some aspect of the NYISO's demand response program recruited customers to participate in EDRP in 2003 (Chart 4.4). Half (4 of 8) expected that the benefits of participation would be lower in 2003 than in 2002 (Chart 4.5). One important change in EDRP is a consequence of decoupling ICAP/SCR; the dispatch rules were changed so that ICAP/SCR resources could be called first, and EDRP curtailments would be called only if needed.[5] Moreover, the NYISO undertook initiatives to increase available capacity. As more customers gravitate to ICAP/SCR because they now also receive an energy payment for curtailments, the odds of needing EDRP curtailments, in addition to what ICAP/SCR provides, are reduced. One respondent believes that higher system reserves would reduce the number of events of any kind that would be called.

Those respondents expecting the EDRP benefits to be the same or greater than in 2002 offered two separate explanations for their views. Two respondents expected that EDRP will still always be called when ICAP/SCR curtailments are invoked, while two others believe that the new provisions of ICAP/SCR will cause customers to switch from that program to EDRP, thereby reducing the amount of ICAP/SCR available for curtailment. If these respondents are correct, the odds of calling the two programs simultaneously would increase, despite the new uncoupling provisions. Perhaps inadvertently, this expectation came to fruition in 2003, but not for the reasons cited. The only curtailment events invoked by the NYISO under either program in 2003 were on August 15 and 16, coincident with the blackout that necessitated calling both programs.[6]

Five of these respondents thought that the policy to uncouple EDRP and ICAP/SCR had no effect on their EDRP marketing efforts. One respondent said that marketing efforts became easier, and two reported greater difficulties in EDRP marketing efforts (Chart 4.6). Most

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indexed to the NYISO DAM prices are posted a day ahead.

[5] ICAP/SCR participants must have first been given a day-ahead notice that a curtailment was possible the next day. If the day-ahead notice does not occur, then compliance to an ICAP/SCR curtailment call is voluntary. This was the case on August 15th, the day of the Northeast blackout and a substantial number of curtailments were provided, probably in large part because of the energy payments that accompanied them.

[6] EDRP was called on August 15 but ICAP/SCR was not called until the next day because day-ahead notice is required. However, on August 15 ICAP/SCR customers were asked to curtail on a voluntary basis with the prospect of receiving an energy payment.

respondents marketing EDRP said that prior years' EDRP participants remained satisfied (4 of 7) or highly satisfied (1 of 7) with the 2003 offering. One reported that its customers were very dissatisfied (Chart 4.7). Finally, in response to an inquiry about participation in 2003 relative to 2002, three of seven respondents reported greater participation, and four reported it to be down. As shown in Table 4.2, the number of enrolled participants in EDRP declined in 2003. (There are 507 dropouts from 2002 and 269 new subscribers). There was also a decrease in total MWs pledged (from 949 to 854, Table 4.3).

ICAP/SCR Experience

Ten of the survey respondents also recruited customers to ICAP/SCR in 2003; of these ten, six are DRPs (Chart 4.8). Of these ten, eight reported that customers found nominating a strike price to be not difficult at all, or to be only somewhat difficult. Two others said that customers found it difficult to nominate a strike price (Chart 4.9). Most (8 of 10) believe that if the new energy payment provisions of ICAP/SCR were eliminated, participation would decrease (Chart 4.10). Estimates of that reduction range from 50% to 68% of the number of MWs enrolled in 2003 (Chart 4.11). One DRP thought that the inclusion of the energy payment would increase participation and enrolled load by 25%.

Respondents were also asked to indicate how they arrange for ICAP/SCR curtailments in situations where not all of the available curtailment capacity is needed. Two respondents rely on a round-robin dispatch, and two others prorate the curtailment proportionally to all participants. Four others have established no specific protocol since they have not faced that situation. Eight of the 10 respondents prefer the existing practice, which is to have each individual LSE and DRP assign its own curtailment resources. The remaining two prefer having the NYISO dispatch the curtailment obligations to specific participants based on the nominated strike prices.

Program Retention and Migration

The second strategy to help determine the effects of the PRL program changes on participation is to track changes in participation for each customer. This analysis is based on the NYISO's program registration database.

Program Enrollment

Table 4.2 provides a detailed accounting of how participation in the PRL programs has changed from 2002 to 2003. The first column lists 2002 participation by program option.[7] The next five columns of Table 4.2 account for the differences from 2002 to 2003 participation by tracking: a) re-subscriptions in the same program option, b) migration to another program option, c) dropouts from the program option altogether, and d) new subscribers to the program option.

The number of PRL program participants totaled 1,785 in 2002. There were 1,535 EDRP participants, 226 ICAP/SCR participants and 24 DADRP participants. By the fall of 2003, the number of participants in all demand response programs declined by about 10%.[8] However, a more careful examination of the data indicates that the changes in participation differed by program and by NYISO pricing zone.

For example, consider the EDRP participant accounting in the first row of Table 4.2. Tracking the changes between 2002 and 2003 shows that 1,021 of the 2002 EDRP participants re-enrolled in 2003, 507 dropped out, none migrated to DADRP, and seven migrated to ICAP/SCR. There were 269 new customers enrolled in EDRP in 2003. The amount of EDRP curtailable load decreased by 10% (95 MW) between the two years (Table 4.3). The curtailable load from the new participants (148 MW) just barely offset that of the customers that left the program (142 MW). The (53 MW) net reduction in EDRP's curtailable load from 2002 to 2003 is due to the migration of customers to ICAP/SCR, and to changes in the amount of curtailable load subscribed by those that re-enrolled. Thus, while the overall changes in EDRP participation from 2002 are modest, it is important to examine the dropouts and new entrants more closely below to see if there are any discernable patterns of behavior.

The data in Tables 4.2 and 4.3 reveal that ICAP/SCR participation also decreased by 6% (13 participants) but the amount of curtailable load increased by 29% (190 MW). Thus, the average curtailable load per participant increased substantially. As the data in Table 4.2 show, the

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[7] Participation data for 2002 represent enrollments over the summer months and correspond to the values reported in the NYISO's evaluation of 2002 program performance, as described in Neenan Associates and CERTS, January 2003.

[8] A participant is defined by a single customer or an aggregation of customers.

drop in participation occurred despite the 89 new enrollees. There are 76 that left the program, and another 33 that switched to EDRP. Clearly, the new participants pledged more curtailable load than was lost through attrition (Table 4.3). The average curtailment of new participants is 3.8 MW, while that of customers leaving the program is only 2.0. It appears that ICAP/SCR participation in 2003 was attractive to customers with larger curtailment capability, but the data may be slightly misleading because some of the participants represent aggregations comprised of several, or in some cases many, customers.

Load subscribed to DADRP increased slightly (4%), proportionally less than the increase in enrollment (13%). The added participants are new to this program.

Zonal Distribution of Program Participants

In addition to there being changes in participation among the PRL programs, the location of participants has changed.

Table 4.4 contains data on program participation by NYISO pricing zone and Table 4.5 records the changes in program composition by zone. Zones J (New York City) and K (Long Island), for example, account for 69% of EDRP participants but only 33% of curtailable load that is enrolled in EDRP. The difference is due, in large measure, to the large number of residential customers and small businesses in these zones that are aggregated for program purposes. Similarly, these same two zones account for 37% of ICAP/SCR participants, but only 16% of total load enrolled. It appears that building up the stock of curtailable load downstate will require recruiting a lot of new customers.

Of the total of 507 EDRP dropouts in 2003, 55% (281) came from zones J and K. The statewide total of new participants was only 269. With three exceptions (zones F, G, and H) the EDRP dropouts exceeded new enrollees in the other zones. In terms of MW, the story is similar. Zones J and K had a total of 61 EDRP-enrolled MW drop out in 2003, and only 39 MW of new enrollment (Table 4.6).

The data in Tables 4.5 and 4.6 distinguish changes in participants and curtailable load for EDRP and ICAP/SCR in one additional important way: as being Sold or Unsold. This distinction highlights a subtle, but important PRL program provision new in 2003. In contrast to earlier years, customers could not enroll the same load in both ICAP/SCR and EDRP. However, customers that enrolled in ICAP/SCR were not necessarily able to sell their ICAP to an LSE. Consequently, they may have had to offer their curtailable load into the NYISO ICAP six-month strip auction or into the monthly reconfiguration auction. If their bids were not accepted in one of these two auctions, they were not eligible for payment under the ICAP program, and are, therefore, not active participants the ICAP/SCR program. Under these circumstances, the NYISO temporarily enrolls the customer in EDRP—thus making the customer eligible for payments for voluntary curtailments, until such time as the customer successfully sells its ICAP. As seen by the data in Table 4.6, this provision was used only in a small number of cases, because most ICAP/SCR enrollees sold their capacity to an LSE or had their load purchased in one of the two auctions.

To recap the discussion so far, participation in EDRP measured in the number of customers enrolled fell from 2002 to 2003, as did the load available for curtailment. Is this an emerging trend? The data in Table 4.7 address this question, by showing changes in participants from 2001 to 2002, and also from 2002 to 2003. As data in the first two columns illustrates, 2002, the second year of the program marked by aggressive marketing by CSPs, was a big growth year for EDRP participation; there were 1,497 new participants and only 117 dropouts from 2001. In 2003, there was a net reduction in participation (269 new, 507 dropouts).

This is not necessarily an indication that the program has reached its apex and is now in decline. Rather, another interpretation of the data would suggest that the EDRP program is maturing. A closer examination of the 507 EDRP dropouts from 2002 to 2003 reveals that 41% (208) of them provided no load curtailment during the 11 hours of EDRP events in 2002 (Table 4.8, Panel D). Thus the loss of these "participants" had no effect on the performance of EDRP load as a resource. The simple, no-penalty provisions of EDRP are designed to attract customers that can then gain experience with load management, at little risk. Through EDRP, one would hope that many would find that they have more control over their usage than they had first anticipated. For those for which this is the case, they may in the future either increase their level of EDRP participation, or switch to one of the other PRL programs. However, it should also be expected that other customers, still finding little capacity or willingness to manage load, or having their circumstances otherwise change, could still drop out after a year or two. Thus, for EDRP to experience these kinds of changes poses no long-term problem, as long as there are new entrants to take the place of those leaving the program. Put differently, if it is customers having difficulties managing load that leave the program, the program's efficiency and effectiveness is actually improved, as dispatchers can better estimate the effect of a call for curtailments.

Another question is: from where did the new ICAP/SCR participants in 2003 come? The 89 ICAP/SCR participants were classified as new entrants in 2003 because they were not registered in ICAP/SCR during 2002. However, they could have participated previously in 2001, but could have just taken a year off in 2002. An examination of the 2001 records reveals that only three of the new 2003 participants had participated in ICAP/SCR in 2001. The rest of them are new to the program, an indication that LSEs and DRPs are actively working on establishing new accounts to increase program participation. This is a clear sign of a robust program.

Strike Price Nominations for ICAP/SCR

Before moving on to other components of this year's PRL program evaluation, it is important to examine one remaining feature of the ICAP/SCR program that is new for 2003. This provision requires ICAP/SCR participants' to nominate a strike price in order to establish priorities for the partial dispatch of ICAP/SCR load curtailments. It was argued above that the need for ICAP/SCR participants to nominate a strike price might reduce the attractiveness of the program. For those remaining participants, one might expect low strike prices from customers confident in their abilities to comply when asked to curtail. Other customers, content with the ICAP/SCR payment, and attempting to limit their curtailment exposure, might routinely bid high strike prices. To shed some light on the validity of these propositions, Chart 4.12 contains the bid curves for ICAP/SCR participants, grouped according to their years of experience in the program.

There is, in fact, substantial clustering of bids around the two extremes. For example, the bid curve for the first-year participants has two distinct clusters, and one very steep but narrow segment (representing less than 5% of the bids). The shape of the curve clearly supports the maintained hypothesis that some customers want to be curtailed, (e.g., strike prices at or near zero), while others may be trying to avoid curtailments by bidding strike prices at or near the $500 ceiling. For customers in the program for two years, over 60% of the strike prices are at or near the $500/MW ceiling, while there is almost no clustering at the low end. For customers in the program for three years, there is some clustering of the bids at both extremes, but over 70% of customer bids are between $250/MW and $300/MW.

While the clustering of these bids can certainly be explained by customer behavior of the kind described above, it could also be the consequence of polar views of the market postulated by the LSEs and DRPs that promote participation. Some might universally recommend that customers bid low to be guaranteed an energy payment at every opportunity. Since, under NYISO scarcity pricing rules, the prevailing ICAP/SCR payment rate can set LBMP, other LSEs or DRPs may recommend that customers bid high to guarantee a high market price, and, therefore, a correspondingly high energy payment. For this strategy to work effectively, most participants would have to bid high enough to ensure a high price even under partial dispatch of the curtailable load by the NYISO.

The above hypotheses are plausible explanations for these clustered strike price nominations, and clearly other explanations are possible. Regardless of the reasons, bid clustering will clearly complicate the use of these strike prices, by an LSE or DRP, to effect a partial dispatch of curtailable load during events requiring less than the total amount of enrolled resources. In contrast, a partial dispatch based simply on prorating every customer's load is far less complicated for the NYISO, which is responsible only for determining the quantity to be curtailed, not for which participants are asked to meet the requirement.

A Brief Summary

There are several important conclusions regarding the effects of this year's changes in EDRP and ICAP/SCR to be drawn from this examination of the survey results and the registration data.

1. There is little evidence to suggest that the changes in the programs were the cause for any substantial migration of customers from EDRP to ICAP/SCR. Participation in ICAP/SCR did increase dramatically, but it was not due to migration from EDRP; rather, it was from new subscribers, and large ones at that.
2. There is also little evidence that ICAP/SCR participants would find it challenging to nominate a strike price for curtailments, thereby being a deterrent to participation. LSEs and DRPs report that most customers were able to meet this requirement with

little difficulty, a belief that is consistent with the large increase in ICAP/SCR participation in 2003. This year, there were 76 customers that left ICAP/SCR; and there is no way to know if this new requirement to nominate a strike price contributed to their departure decisions. However, the fact that these "dropouts" (by definition) did not even participate in EDRP, which requires no strike price and imposes no penalty for failure to comply, suggests that these departing customers more likely based their decisions on the difficulty of curtailing loads (for business or other reasons) rather than on changes in the ICAP/SCR program.

3. Finally, curtailment bids by ICAP/SCR participants are indeed highly clustered around very low and very high values. While there is nothing inherently inconsistent or questionable about that outcome, it does complicate implementing a curtailment that requires only a fraction of the available curtailable loads.

The Results of the Evaluation of EDRP Resources

As indicated above, EDRP events were only called on August 15th and 16th, the two days following the Northeast blackout of August 14, 2003. On those two days, the real-time LBMPs in all zones were set administratively at the day-ahead LBMPs; thus, there is no basis from which to estimate the market effects of EDRP load reduction on those event days. Even though it is impossible to estimate any market effects of EDRP load reduction for 2003, it is clear from the previous evaluations for 2001 and 2002 that under more "normal" EDRP events, the value of EDRP load reduction, in terms of reductions in price, collateral benefits, and reduction in price variability was substantial in those two years (Neenan Associates, 2002, and Neenan Associates and CERTS, 2003). However, under 2003 protocols, the load reduction resources can now set LBMP, and the ICAP/SCR dispatch strike price (which could be as high as $500/MWH) or the EDRP price floor ($500/MWH) could effectively place a floor on the real-time LBMP during emergency events. Therefore, it is possible that this protocol could lead to higher prices during those periods when EDRP and ICAP/SCR are dispatched than would have been the case in previous years. While it is difficult to say if this change would increase or decrease price variability, it would almost surely reduce the size of any collateral benefits to customers.

Given this uncertainty with respect to market effects, the evaluation of the EDRP events in 2003 clearly must focus almost exclusively on the effect of the load reduction on system reliability. As indicated above, the methodology for evaluating the effects of EDRP load reduction in the days immediately following the blackout had to be modified from that of previous years. In addition to modifying the methodology, the availability of more detailed data on reserve margins during the two event days assisted in the evaluation.[9]

As argued above, the standard methodology is used to quantify the reliability benefits of EDRP, by first determining by how much the curtailments improved LOLP. Then, the improvement in LOLP must be converted into a dollar value of benefit to customers. This expectation is converted into a corresponding dollar value to customers, by multiplying the change in expectations of an outage by the amount of load that is subject to an outage to estimate the change in the expected amount of load subject to an outage. In turn, this number is multiplied by the value of lost load (VOLL)—yielding a measure of the cost to consumers when service is curtailed under such circumstances. However, in the case where the system is restored step-by-step, each curtailed MWH corresponds to the moving of another MWH from the state where its LOLP is one and the expected unserved energy for these customers is equal to the load they would use, if they could be brought back on line. There is thus a one-to-one correspondence between EDRP and ICAP/SCR curtailment resources and the corresponding expected unserved energy. With this unique relationship established, valuing these curtailments can be accomplished by using the conventional methods multiplying this quantity by the value of lost load.

Based on these methods, the estimates of the system reliability benefits of the EDRP events following the 2003 blackout are given in Table 4.9 for a range of outage cost values and

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[9] In contrast to this year's evaluation, the evaluation of EDRP in 2001 in terms of system reliability by Neenan Associates (2002) relied on data on reserves for only one of the event hours. In that report, the EDRP reliability benefits were estimated, during the hour examined, for four different levels of LOLP reductions, ranging from 0.05 to 0.50, and for four levels of outage cost. The average hourly system benefits outstrip the hourly program payments of about $182,000 by a very wide margin under every combination of LOLP and outage cost assumptions displayed in the table. The lowest benefit/cost ratio was over seven under the assumption that the entire system load was at risk of being interrupted. Further, even under a more stringent view, when only 5% of load was at risk for interruption and outage costs in the range of $2,500-5,000/MWH, the benefit/cost ratio for that hour was between 4.8 to one to 9.5 to one. Similar conclusions were reached in the 2002 EDRP evaluation (Neenan Associates and CERTS, 2003).

load at risk. In this table, load at risk is defined either in terms of the percentage of actual EDRP/SCR MWs of performance, or in terms of the percentage of EDRP/SCR performance needed to meet the 30-minute reserve margin. Both estimates of load at risk are conservative, but it is the latter definition that provides the *most* conservative estimate of the load at risk, and it is this definition that is consistent with the modified methodology applied to the events of August 16, 2003.

As one might expect because of the differences in methodology, the results also differ somewhat across the two days. On August 15, 2003, there was an hourly average of 803 MWh of load reduction, with 56% coming from EDRP participants, and 44% coming from ICAP/SCR participants. Program costs were just over $5.8 million,[10] and depending on the assumptions about load at risk and outage costs, system benefit/cost ratios range from 1.9 to 19.2 (Table 4.9).

On August 16, 2003, a Saturday, the hourly average load reduction was 473 MWh, with 37% coming from EDRP participants, and 63% coming from ICAP/SCR participants. The program payments to those that curtailed were just under $1.7 million,[11] but in contrast to the results of August 15th, the system benefit/cost ratio was less than one, if outage costs are assumed to be only $1,000/MW. It was argued above, however, that where the outage is widespread and is of an extended duration, customers have little recourse except to endure the hardships of an outage. Under these circumstances, the use of higher VOLL in estimating the value of PRL program load curtailment resources would seem appropriate. Under this assumption (where outage costs are assumed to be at least $2,500/MW) the system benefit/cost ratio of EDRP/SCR load reduction on the 16th would range from 1.0 to 3.8, depending on the assumptions regarding load at risk (Table 4.9).

The Results of the DADRP Evaluation

In all three years that DADRP has been in operation, bids have been scheduled during the winter and spring months, as well as during the summer months. For the past two years, however,

[10] These payments are for energy only.

[11] These payments are for energy only.

only the bids for the summer months have been examined. This was, in part, to maintain consistency with the EDRP evaluations.

Because of the current interest in the efficacy of DADRP, however, this year's evaluation does include data for the winter and spring months, as well as for the summer months of 2003. Both the market effects and the social welfare evaluation were conducted for the complete set of data.[12] Further, since the data are available from previous years, the social welfare evaluation is also conducted for the summer months of 2001 and 2002.

This additional analysis contributes to the program evaluations in those years and to the evaluation of the efficacy of DADRP.

The Market Effects of DADRP

The market effects of DADRP for the winter and spring months combined and for the summer months are summarized in Tables 4.10 and 4.11, respectively. For 2003 as a whole, DADRP bids were scheduled only in the Capital Zone and in Western New York. During the winter and spring, bids were scheduled only in the Capital Zone. During the summer, bids were scheduled both in the Capital Zone and in Western New York.

During the winter and spring of 2003, there were 909 DADRP bids accepted (Table 4.10, Column 5). There was a total of 1893 MW scheduled, corresponding to an hourly average of 2MW (Table 4.10, Column 5). Program payments totaled $142,167, for an average of $156 per bid, see Table 4.14.

During the hours in which bids were scheduled, the load was reduced by about 0.1% relative to what it would have been otherwise (Table 4.10, Column 8). Without the scheduled bids, the LBMP in the DAM would have averaged $71.43/MW, up slightly from $71.29—an

[12] The supply flexibilities for the aggregate Capital-Hudson super zone are used throughout in evaluating the market and social welfare effects of DADRP in the Capital Zone. It should also be noted that because most of the scheduled DADRP bids are during hours of relatively small fixed bid load in the DAM, the supply flexibilities in the first regime of the day-ahead "spline" supply model are used extensively in the evaluation of the market and social welfare effects of DADRP. Since the supply flexibilities in the real-time market are also needed to estimate the social welfare implications of DADRP, the supply flexibilities in the first regime of the real-time "spline" supply model are used extensively as well. For the year 2003, these supply flexibilities are reported in Appendix 3A. For the two previous years, the appropriate supply flexibilities are reported in Neenan, 2002 and Neenan and CERTS, 2003.

estimated 0.2% price reduction due to DADRP (Table 4.10, Columns 7, 4, and 9, respectively). The bill savings spread across all customers in the zone are estimated at $223,426 (Table 4.10, Column 11).

During the summer of 2003, there were 628 bids scheduled in DADRP, all but 18 of which were in the Capital Zone (Table 4.11, column 5). Program payments totaled $121,144, with 92% of them going to customers in the Capital Zone, see Table 4.15.

The total load reduction from scheduled DADRP bids during the summer months was 1,752MW, with 90% occurring in the Capital Zone (Table 4.11, column 5). The average load reduction per scheduled bid was 3MW in the Capital Zone and was 10MW in Western New York.

With these small average load reductions (less than 0.1% of load), it is not surprising that the effects on LBMP in both the Capital Zone and in Western New York were small as well. In the Capital Zone, LBMP without the scheduled load reduction would have been on average less than 0.1% higher in the hours where bids were scheduled. In Western New York, the LBMPs in those hours would have been on average 0.1% higher without the scheduled bids. Having this scheduled load reduction would in turn lead to system wide bill savings of $45,772—with 92% of the savings going to the Capital Zone.

The Social Welfare Effects of DADRP

The market effects of DADRP in 2003 are quite small, as was found to be the case as well during 2001 and 2002 (Neenan Associates, 2002, and Neenan Associates and CERTS, 2003). This is primarily the result of the small number of participants in the program (see above), the relatively low level of active bidding, and the relatively small number of scheduled bids. It is also the case that the bid strike prices are relatively low, and the bids are scheduled during times when load is not terribly large.

These factors clearly raise questions about the extent to which DADRP is or can be made an effective way for customers to participate in the day-ahead market by adjusting load in response to price, and being paid to do so. To shed some light on this issue, this year's PRL program evaluation included an examination of the improvements in market efficiency due to DADRP. As discussed above, this involves measuring the reduction in the deadweight social losses avoided at times when bids are scheduled and customers effectively are able to reduce load in response to price. These efficiency gains from responding to market prices essentially are the savings in the cost of electricity over and above its value to customers facing fixed prices compared to those customers adjusting load in response to price. This difference between the value to customers and the cost of the load purchased at the fixed tariff can be shown to be equal to the area d + d' in Exhibit 3.4. However, if customers bid load reduction through DADRP, there is the potential to avoid some of this deadweight social loss, as long as 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.

The size of these two areas is clearly an empirical question. 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, however, is made only once.[13]

Because of the importance of this issue, this welfare analysis is conducted for the summers of 2001, 2002, and 2003, as well as for the combined winter and spring (referred to in the tables as "Winter") months of 2003, and the results are reported in Tables 4.12 through 4.15. Each table reports the program payments (column 2), the deadweight losses avoided due to DADRP load in the day-ahead market (column 3) and the real-time market (column 4), and the change in net social welfare (column 5). The change in net social welfare is defined as the sum of the deadweight losses avoided less the program payments.

Perhaps the most striking feature of these results is the difference between the net social welfare benefits in summer 2001, compared with those in subsequent years. In DADRP's first

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[13] It is important to reiterate from above that 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, 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. Although the effects of this potential buy through are not simulated here, the entire social welfare analysis speaks directly to the long- term efficacy of DADRP.

year of operation, the change in net social welfare was positive. For subsequent years, it is negative.

In 2001, the change in net social welfare from DADRP is positive, and in relative terms, substantially so. The reduction in deadweight losses in the DAM and RTM markets combined totaled $256,932 (Table 4.12, the sum of columns 3 and 4), exceeding program payments of $213,944 by $42,737. The positive change in net social welfare is due entirely to scheduled bids in the Capital Zone. In Western New York, the net change is slightly negative, $-752 (Table 4.12, column 5). On a per hour or bid basis, the net change in social welfare averaged $118 in the Capital Zone, and $-3 in Western New York.

In contrast to these results, there was a net reduction in social welfare due to DADRP during the summer of 2002. Program payments of $110,294 exceed the combined reduction in deadweight losses, and net social welfare declined by $23,919 (Table 4.13, column 5). Hourly average changes in net social welfare are $-69 and $-35 in the Capital Zone and Western New York, respectively.

For the Capital Zone, the story is similar for the combined winter and spring months of 2003. Program payments of $142,167 exceeded the reduction in deadweight losses by $25,869 (Table 4.14, columns 2 and 5). On an hourly basis, however, the average reduction in net social welfare is only $28 (Table 4.14), substantially below the average reduction of $69 for the summer of a year earlier (Table 4.13).

During the summer of 2003, the change in net social welfare from scheduled DADRP bids is also negative. Program payments of $121,144 exceeded reductions in deadweight losses by $72,271 (Table 4.15, Columns 2 and 5). For the Capital Zone, the reduction in net social welfare on an hourly average basis was $104. For the 18 scheduled bids in the Western New York region, net social welfare was reduced by an average of $479 (Table 4.15).

The significance of these yearly results for policy and program design lies in the substantial variation in the net change in social welfare on an hourly basis. In some cases, the change was a large positive number, while in others, the net change was negative. The important task is to identify any systematic relationship between market conditions and the size of the net change in social welfare. The theory outlined above and in Appendix 3A provides an initial guide to this analysis. In particular, 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 led to price spikes that disrupt newly formed wholesale markets.

To identify the importance of these and other factors, the hourly changes in net social welfare are regressed on several market variables. Results of the estimated regression equation are reported in Table 4.16. The six variables used in the regression reflect market conditions in both the DAM and RTM, and they explain 75% of the variation in net social welfare changes due to scheduled DADRP bids. All but one of the variables is statistically significant.

The results of the regression analysis can be summarized in the following way. Net social welfare increases as the supply price flexibilities in both markets, increase. The strength of this effect is nearly the same for both markets (estimated coefficients on the DAM flexibility and RTM flexibility terms are 44 and 41, respectively). Net social welfare also increases as the load in the real time market increases. Merely because of a scale effect, the net social welfare also increases with the size of the DADRP load scheduled. On the other hand, net social welfare decreases as the ratio of the LBMP in the DAM to the LBMP in the RTM rises.

If one were to translate these findings into recommendations for making long-term changes in DADRP, the following changes could be recommended:

1. To ensure positive changes in net social welfare the program should contain some type of minimum bid threshold.
2. This threshold should be dynamically determined, based on the forecasted price differences between the DAM and RTM, as well as the "steepness" of the supply curves in both markets, as measured by the supply price flexibilities.
3. Since deadweight losses are reduced when more energy is purchased at prices below some fixed tariff, (Appendix 3A), it follows that there ought to be provisions for participants to "buy through" when RT LBMP is less than the DAM LBMP at which the DADRP load reduction bid was scheduled.

Table 4.1 Survey Respondents

• Regulated LSE	2
• Competitive LSE	3
• Demand Response Provider	6
• Retail Customer	1
• Other-Non-Profit Agency	1
• TOTAL	13

Table 4.2 Program Participation Summary

	Total 2002 (count)	2003 (count)					
		EDRP	**DADRP**	**ICAP**	**Dropped**	**New**	**Total 2003**
EDRP	1535	1021	0	7	507	269	**1323**
ICAP	226	33	0	117	76	89	**213**
DADRP	24	0	24	0	0	3	**27**
sub	1785	1054	24	124			
	NEW 2003	*269*	*3*	*89*			
		1323	**27**	**213**			

Table 4.3 Program Participation Summary – MW

	Total 2002 (MW)	2003 (MW)						
		EDRP	**DADRP**	**ICAP**	**Dropped**	**New**	**Re-enrolled changes to subscription**	**Total 2003**
EDRP	949.13	753.92	0.00	52.80	142.41	147.96	-76.39	**853.99**
ICAP	659.50	28.50	0.00	476.40	154.60	332.70	-11.60	**850.30**
DADRP	393.80	0.00	393.80	0.00	0.00	22.50	-5.00	**411.30**
sub	2002.43	782.42	393.80	529.20				
	NEW 2003	*147.96*	22.50	332.70				
	Re-enrolled changes to subscription	-76.39	-5.00	-11.60				
		853.99	**411.30**	**850.30**				

Table 4.4 Program Participation By Zone

	EDRP		**DADRP**		**ICAP**	
Zone	**#**	**MW**	**#**	**MW**	**#**	**MW**
A	54	53.38	9	162.40	39	399.00
B	16	62.59	0	0.00	17	30.20
C	145	36.78	4	40.40	31	75.90
D	9	219.43	0	0.00	5	108.60
E	46	55.67	3	114.00	9	14.10
F	66	68.98	9	91.00	14	68.80
G	42	58.97	0	0.00	1	0.40
H	8	7.20	1	1.00	4	2.40
I	25	13.04	0	0.00	14	12.00
J	107	98.72	1	2.50	67	130.30
K	805	179.24	0	0.00	12	8.60
Total	***1323***	***853.994***	***27***	***411.30***	***213***	***850.30***

Table 4.5 Migration By Zone

Zone	EDRP				ICAP					DADRP	
	Dropped	***EDRP to ICAP Sold***	***EDRP to ICAP Un-Sold***	***New***	***Dropped***	***ICAP Sold to EDRP***	***ICAP Un-Sold to EDRP***	***New Sold***	***New Un-Sold***	***Dropped***	***New***
A	55	1		12	28	1	1	12	4		
B	58			9	12			5			
C	61	2		35	1	1		11			
D	4			1	2			4			
E	34	1		13	4			7	1		
F	8	1	1	28	2	1		2			2
G	1			14		2					
H				2				1			
I	5			13	2	1		3	1		
J	60			59	20	3		33	4		1
K	221	1		83	5	23		1			
Total	**507**	**6**	**1**	**269**	**76**	**32**	**1**	**79**	**10**	**0**	**3**

Table 4.6 Participation Changes (2002 to 2003) By Zone – MW

Zone	EDRP (MW)				ICAP (MW)					DADRP (MW)	
	Dropped	***EDRP to ICAP Sold***	***EDRP to ICAP Un-Sold***	***New***	***Dropped***	***ICAP Sold to EDRP***	***ICAP Un-Sold to EDRP***	***New Sold***	***New Un-Sold***	***Dropped***	***New***
A	20.42	43.00		5.78	75.00	0.60	0.10	78.70	3.30		
B	24.38			30.79	7.20			11.00			
C	9.42	1.00		11.70	0.60	0.20		10.90			
D	0.90			0.30	2.30			108.00			
E	19.43	0.30		13.70	5.20			11.70	2.10		
F	4.18	1.20	7.00	24.84	7.90	17.20		16.40			20.00
G	0.10			12.37				0.70			
H				1.50		4.60					
I	2.80			7.74	0.60			4.20	0.40		
J	26.55			20.77	53.30	4.20		83.10	1.70		2.50
K	34.24	0.30		18.47	2.50	1.60		0.50			
Total	**142.41**	**45.80**	**7.00**	**147.96**	**154.60**	**28.40**	**0.10**	**325.20**	**7.50**	**0.00**	**22.50**

Table 4.7 Participation Changes 2001 – 2003

	EDRP		DADRP		ICAP	
	2001 to 2002	2002 to 2003	2001 to 2002	2002 to 2003	2001 to 2002	2002 to 2003
Dropped	117	507	6	0	34	76
New	1497	269	4	3	91	89
Transfers		33				7
Renewals	190	1021	20	24	117	117
	1687	1323	24	27	208	213

Table 4.8 Migration and Dropout Details

Panel A

2002 ICAP to 2003 EDRP with ICAP performance in 2002		
ZONE	#	MW
A	2	0.7
C	1	0.2
F	1	17.2
I	1	0
J	2	1.6
K	18	0.5
Total	**25**	**20.2**

Panel B

New Participants with 2001 Program Experience			
EDRP		**ICAP**	
ZONE	#	ZONE	#
F	1	A	2
		J	1

Panel C

2002 ICAP dropped in 2003 with ICAP performance in 2002		
ZONE	#	MW
A	21	68.9
B	10	6.2
D	1	0.8
E	2	4.9
F	1	7.9
I	1	0.6
J	11	51.3
K	2	1.2
Total	**49**	**141.8**

Panel D

2002 EDRP Dropouts with no performance in 2002 Events	
Zone	**Count**
A	25
B	50
C	50
D	2
E	18
F	5
G	1
H	0
I	1
J	24
K	32
Total	**208**
Western NY	145
Capital	5
Hudson River	2
NYC/LI	56
Total	**208**

All MW reported are subscribed – not performance

Table 4.9 Value of Expected Unserved Energy, Summer 2003

% of Load at Risk	% Load at Risk as % of RT Load	Outage Cost $1,000/MW	Outage Cost $2,500/MW	Outage Cost $5,000/MW	Program Payments
8/15/2003*					
100%	3.8%	$ 11,244,655	$ 28,111,636	$ 56,223,273	$ 5,850,398
B/C ratio		1.9	4.8	9.6	
150%	5.8%	$ 16,866,982	$ 42,167,455	$ 84,334,909	$ 5,850,398
B/C ratio		2.9	7.2	14.4	
200%	7.7%	$ 22,489,309	$ 56,223,273	$ 112,446,546	$ 5,850,398
B/C ratio		3.8	9.6	19.2	
8/16/2003**					
100%	1.7%	$ 645,585	$ 1,613,963	$ 3,227,925	$ 1,680,213
B/C ratio		0.4	1.0	1.9	
150%	2.6%	$ 968,378	$ 2,420,944	$ 4,841,888	$ 1,680,213
B/C ratio		0.6	1.4	2.9	
200%	3.5%	$ 1,291,170	$ 3,227,925	$ 6,455,850	$ 1,680,213
B/C ratio		0.8	1.9	3.8	

* Assumes Change in LOLP=1.0, Load at Risk=EDRP & SCR Perf MWHs

** Assumes Change in LOLP=0.2, Load at Risk = % EDRP & SCR MWHs needed to meet 30-Min Reserve Margins

Table 4.10 Average Zonal and Total Effects of DADRP Scheduled Bids on New York Electricity Markets, Winter 2003

Zone	Fixed Bid Load in the DAM	With DADRP Day-Ahead Load (MW)	With DADRP Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Simulated Day-Ahead Load (MW)	Simulated Day-Ahead LBMP ($/MW)	% Change in Due to DADRP Load	% Change in Due to DADRP LBMP	Arc Price Flexibility*	Bill Savings ($)***
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Capital										
Hourly Avg.	3,684	2,872	71.291	2 (909)*	2,874	71.431	0.1%	0.2%	2.6	246
Total	3,348,669	2,610,513		1,893	2,612,406					223,426
% of G. Total	100%	100%		100%	100%					100%

*The number of bids scheduled.

Table 4.11 Average Zonal and Total Effects of DADRP Scheduled Bids on New York Electricity Markets, Summer, 2003

Zone	Fixed Bid Load in the DAM	With DADRP Day-Ahead Load (MW)	With DADRP Day-Ahead LBMP ($/MW)	DADRP Load (MW)	Simulated Day-Ahead Load (MW)	Simulated Day-Ahead LBMP ($/MW)	% Change in Due to DADRP Load	% Change in Due to DADRP LBMP	Arc Price Flexibility*	Bill Savings ($)***
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Capital										
Hourly Avg.	4,413	3,467	66.1	3 (610)*	3,470	66.1	0.1%	0.0%	0.6	69
Total	2,692,185	2,114,979		1,576	2,116,555					42,244
% of G. Total	96%	95%		90%	95%					92%
Western New York										
Hourly Avg.	7,016	6,581	55.7	10 (18)*	6,591	55.8	0.1%	0.1%	0.6	196
Total	126,280	118,457		176	118,633					3,529
% of G. Total	4%	5%		10%	5%					8%
Grand Total	2,818,465	2,233,436		1,752	2,235,188					45,772

*The number of bids scheduled.

Table 4.12 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Summer 2001

Zone	Program Payments	Reduction in Deadweight Loss# Day Ahead	Reduction in Deadweight Loss# Real-time	Change In Net Social Welfare#
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	376 (370)*	239	255	118
Total	139,170	88,400	94,258	43,489
% of G. Total	65%	68%	74%	102%
Western New York				
Hourly Avg.	268 (279)*	148	119	-3
Total	74,775	41,166	33,107	-752
% of G. Total	35%	32%	26%	-2%
Grand Total	213,944	129,567	127,365	42,737

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.13 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Summer 2002

Zone	Program Payments	Reduction in Deadweight Loss#		Change In Net Social Welfare#
		Day Ahead	Real-time	
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	291 (301)*	154	68	-69
Total	87,494	46,389	20,472	-20,632
% of G. Total	79%	78%	75%	86%
Western New York				
Hourly Avg.	243 (94)*	135	72	-35
Total	22,801	12,720	6,794	-3,287
% of G. Total	21%	22%	25%	14%
Grand Total	110,294	59,109	27,266	-23,919

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.14 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Winter 2003

Zone	Program Payments	Reduction in Deadweight Loss#		Change In Net Social Welfare#
		Day Ahead	Real-time	
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	156	64	64	-28
	(909)*			
Total	142,167	58,196	58,103	-25,869
% of G. Total	100%	100%	100%	100%

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.15 Net Social Welfare from DADRP Scheduled Bids in the NY Electricity Markets, Summer 2003

		Reduction in Deadweight Loss#		
Zone	Program Payments	Day Ahead	Real-time	Change In Net Social Welfare#
(1)	(2)	(3)	(4)	(5)
Capital				
Hourly Avg.	182 (610)*	48	30	-104
Total	111,300	29,323	18,335	-63,643
% of G. Total	92%	97%	99%	88%
Western New York				
Hourly Avg.	547 (18)*	58	9	-479
Total	9,844	1,049	168	-8,628
% of G. Total	8%	3%	1%	12%
Grand Total	121,144	30,371	18,502	-72,271

#The change in deadweight loss and net social welfare are calculated using the methodology in Appendix E.
*The number of bids scheduled.

Table 4.16 Factors Affecting Net Social Welfare from DADRP

Variables	Parameter Estimate	T-value
Intercept	31.12	1.25
dam_price_flex	44.02	2.82
rt_price_flex	41.37	9.46
rt_load	0.02	4.26
dam_load	0.00	-0.27
dadrp_mw	-39.14	-34.32
dam_to_rt_lbmp	-134.39	-15.79
R^2	0.75	

The variables defined below correspond to the hourly zonal variables in the zones in which the DADRP load was scheduled:
dam_price_flex = supply price flexibilitiy in the DAM.
rt_price_flex = supply price flexibility in the real-time market.
rt_load = load in the real time market.
dam_load = load in the DAM
dadrp_mw = the MW's of dadrp load scheduled.
dam_to_rt_lbmp = the ratio of the price in the DAM to that in real tim

Chart 4.1 Which Programs Were Promoted

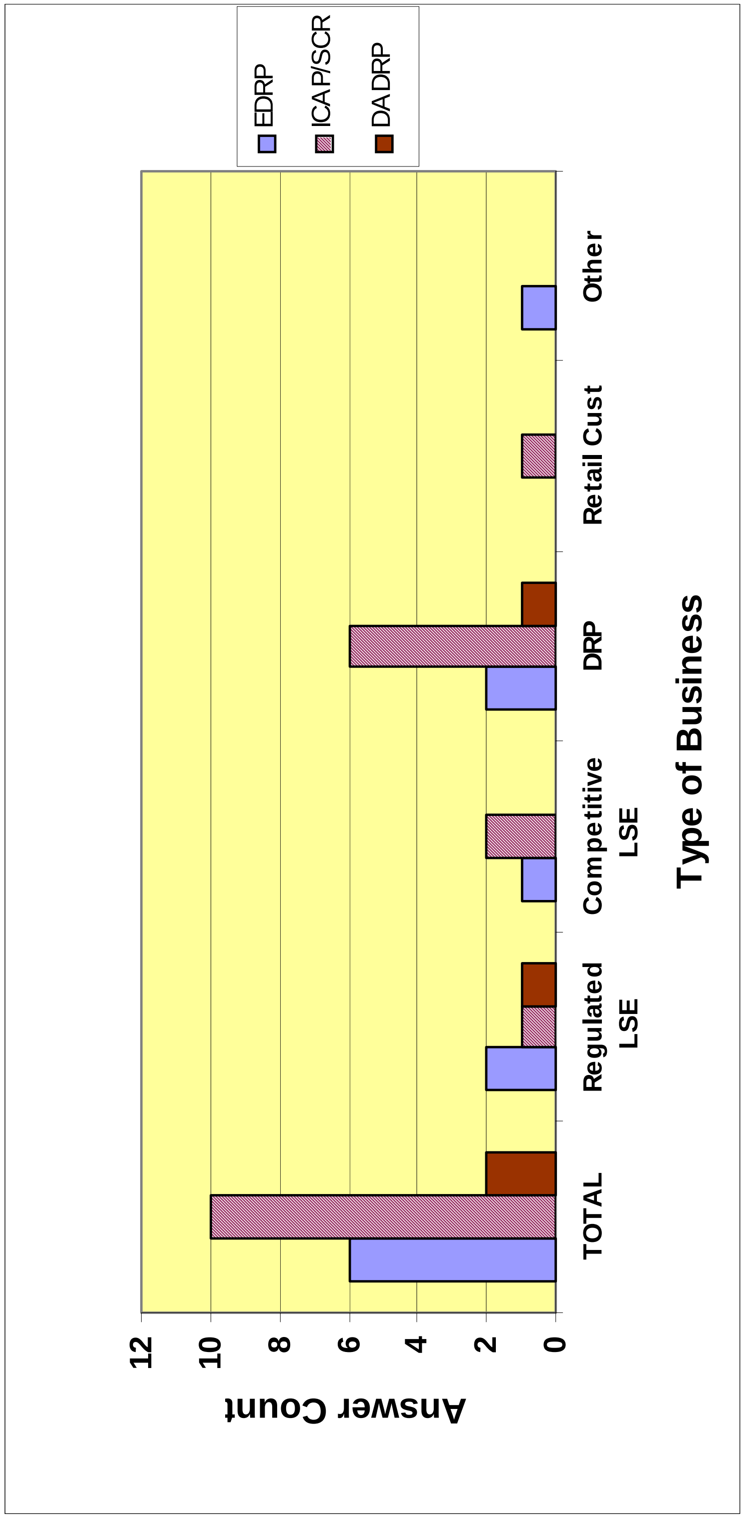

Chart 4.2 Efforts to Promote DADRP Participation

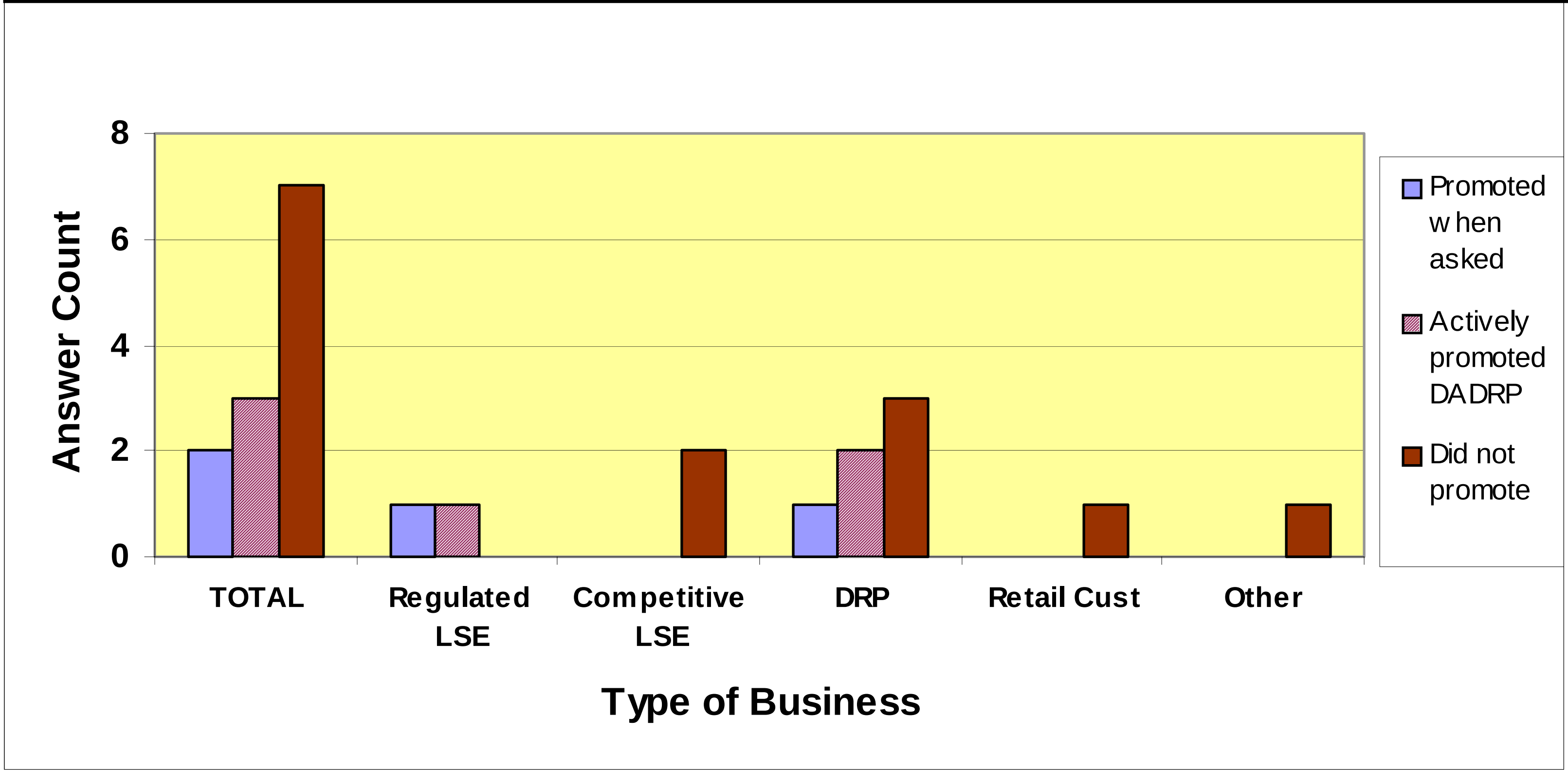

Chart 4.3 Customer Receptiveness to DADRP

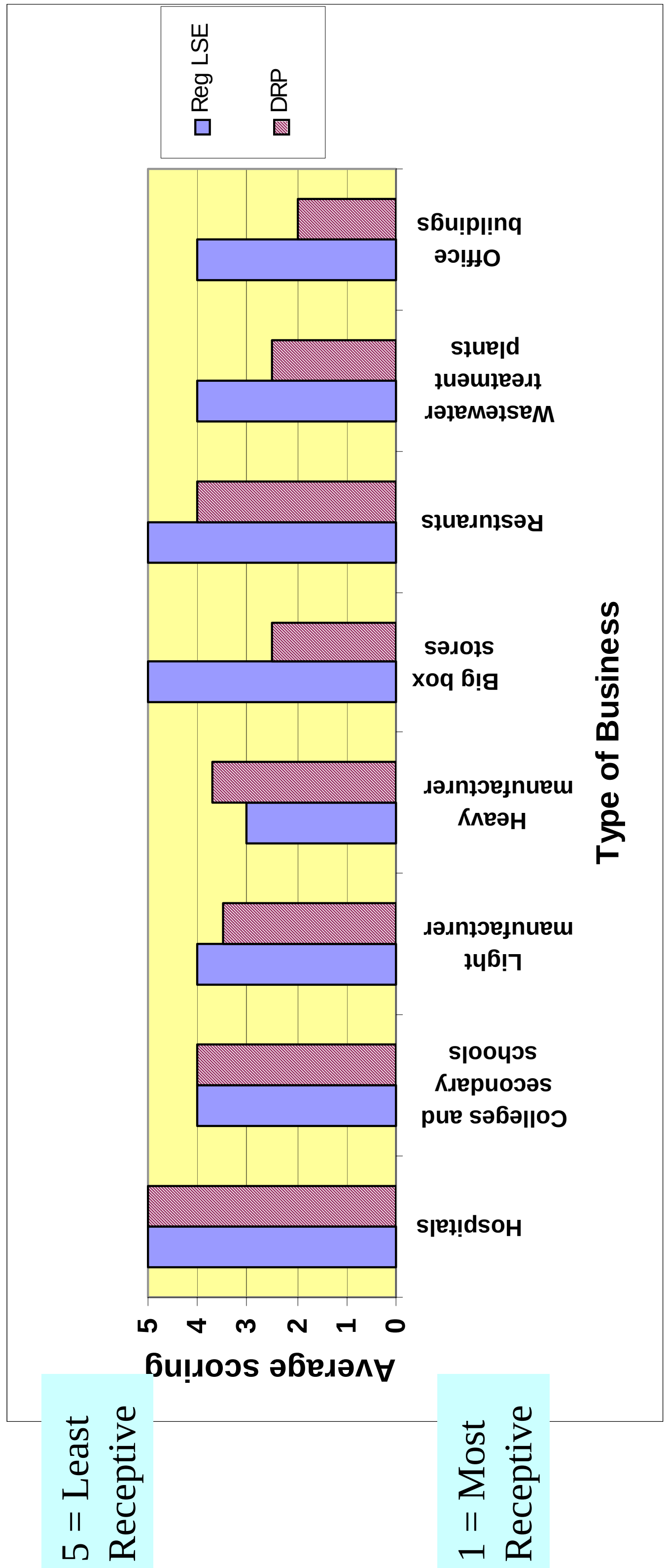

Chart 4.4 Promotion of EDRP Participation

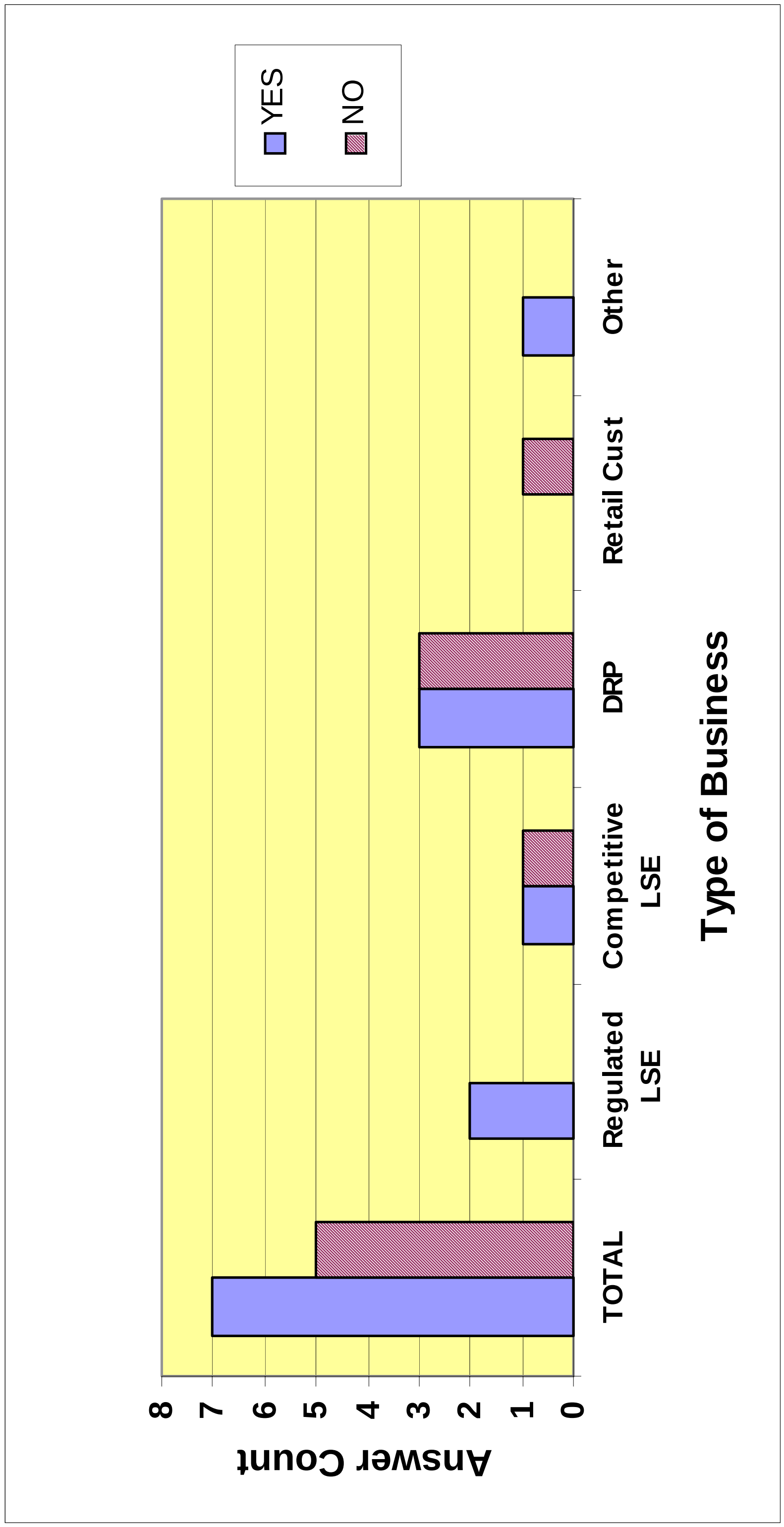

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Chart 4.5 Expectations of 2003 Benefits from EDRP Participation

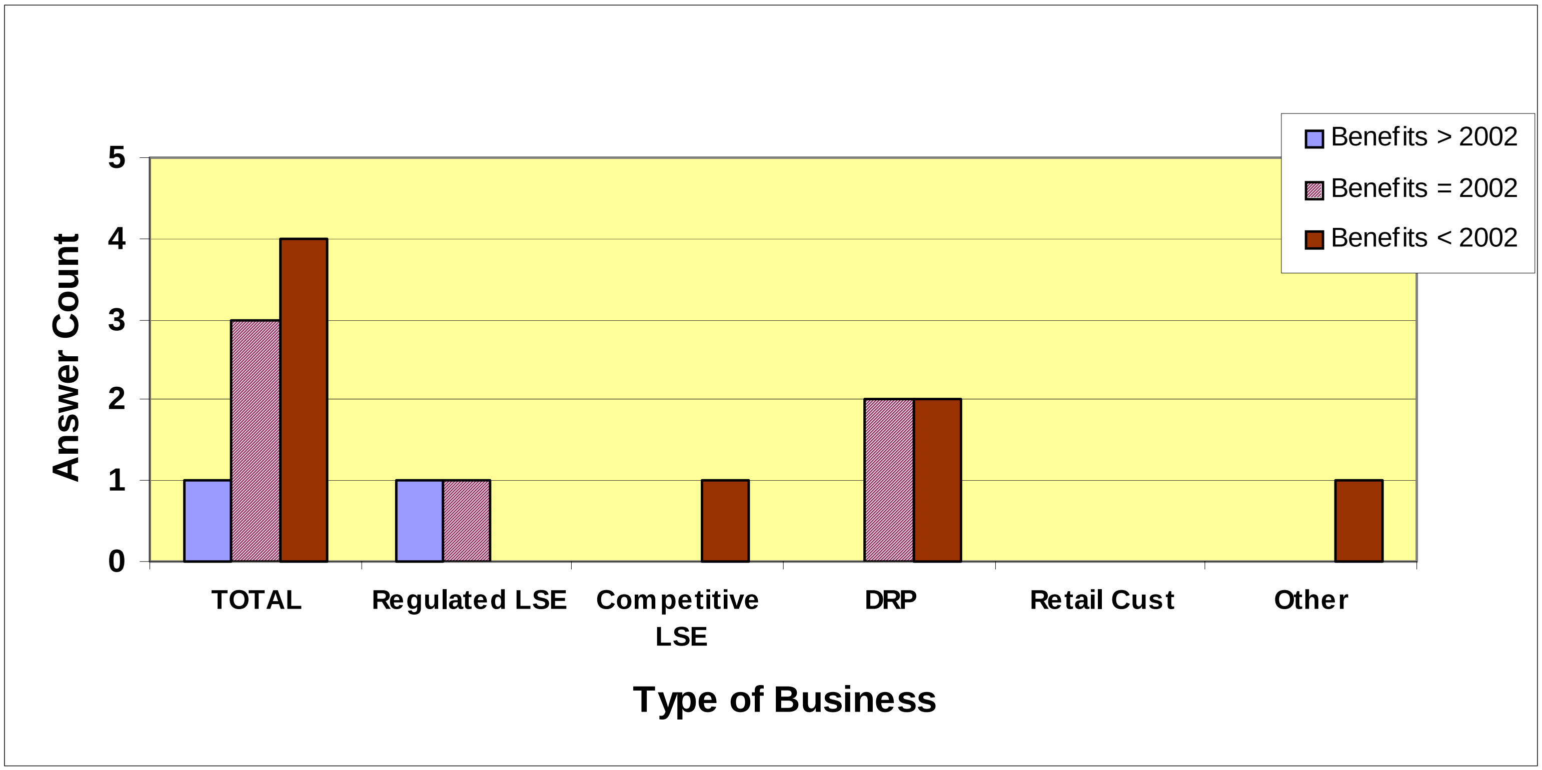

Chart 4.6 Experience in Marketing Revised EDRP

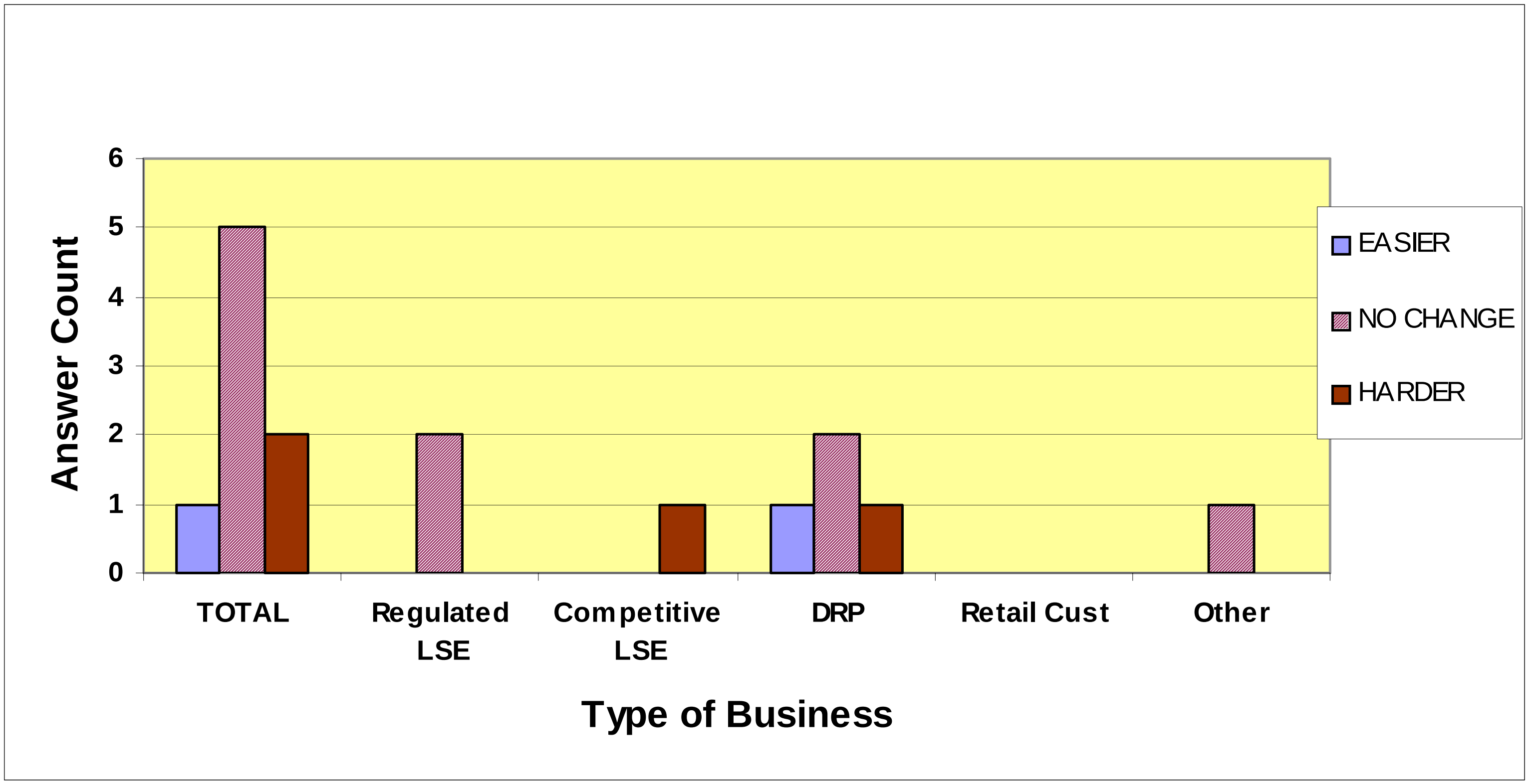

Chart 4.7 Satisfaction with ICAP/EDRP Unbundling

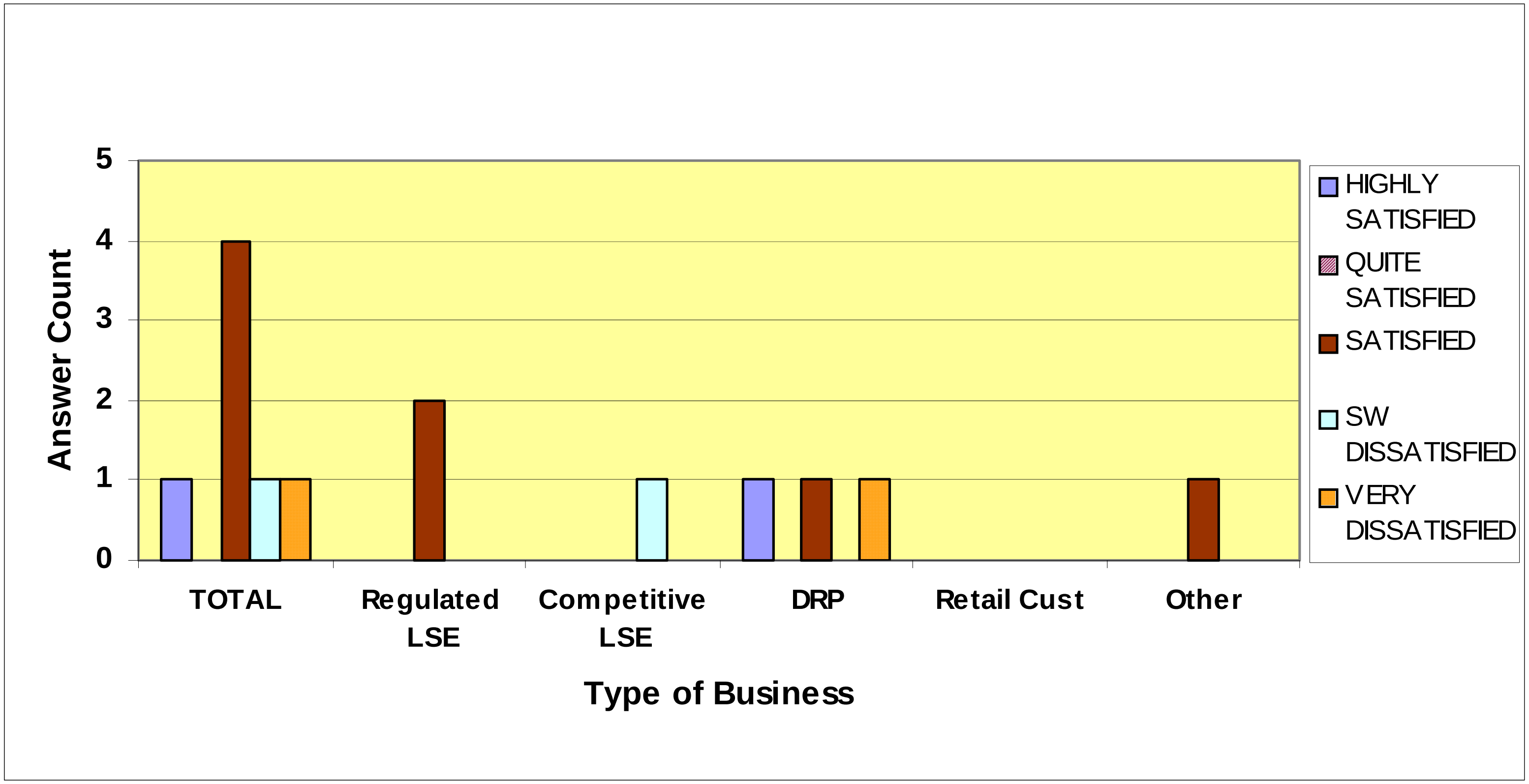

Chart 4.8 Promote ICAP/SCR

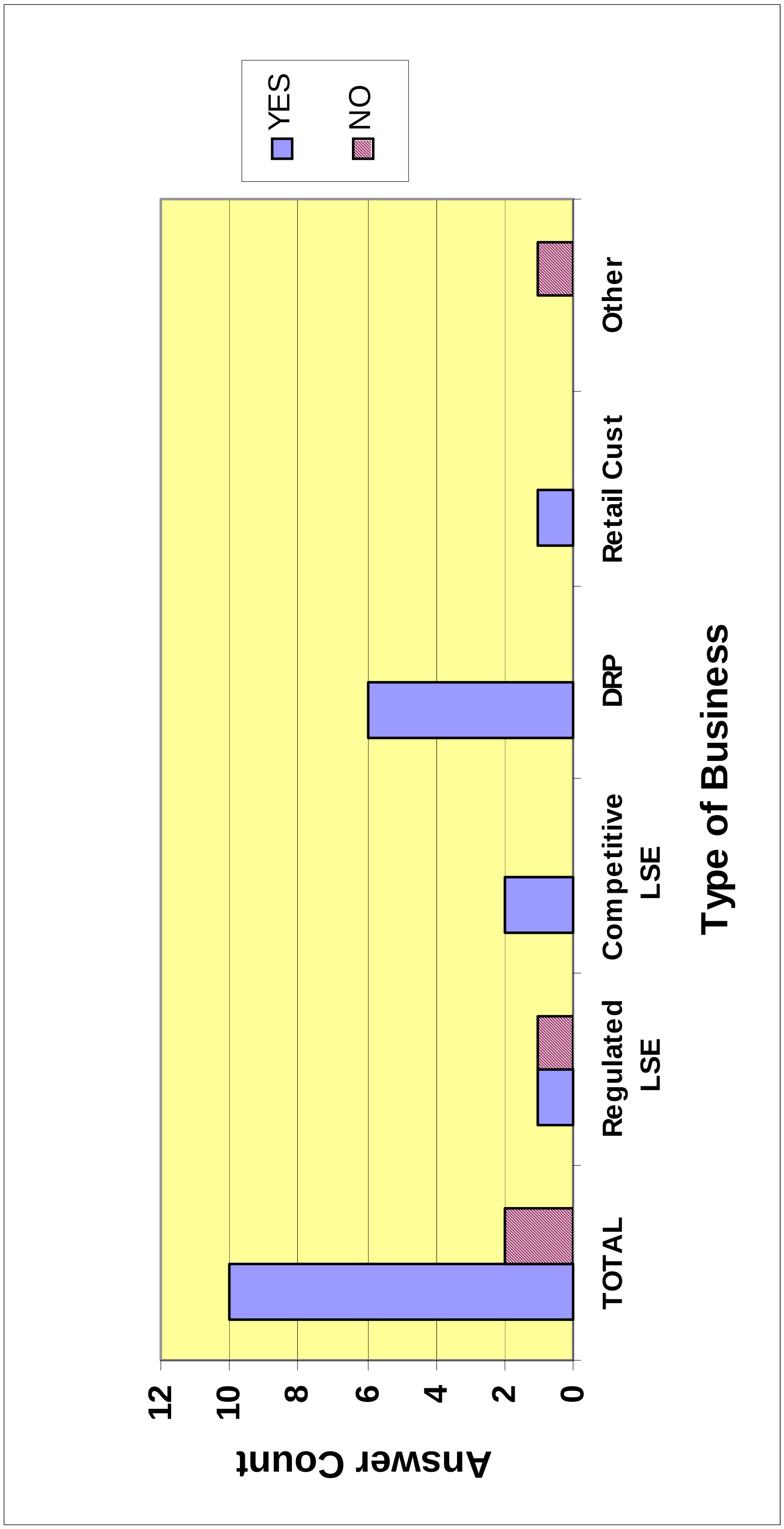

Chart 4.9 Satisfaction with ICAP/SCR Strike Price Nomination Protocols

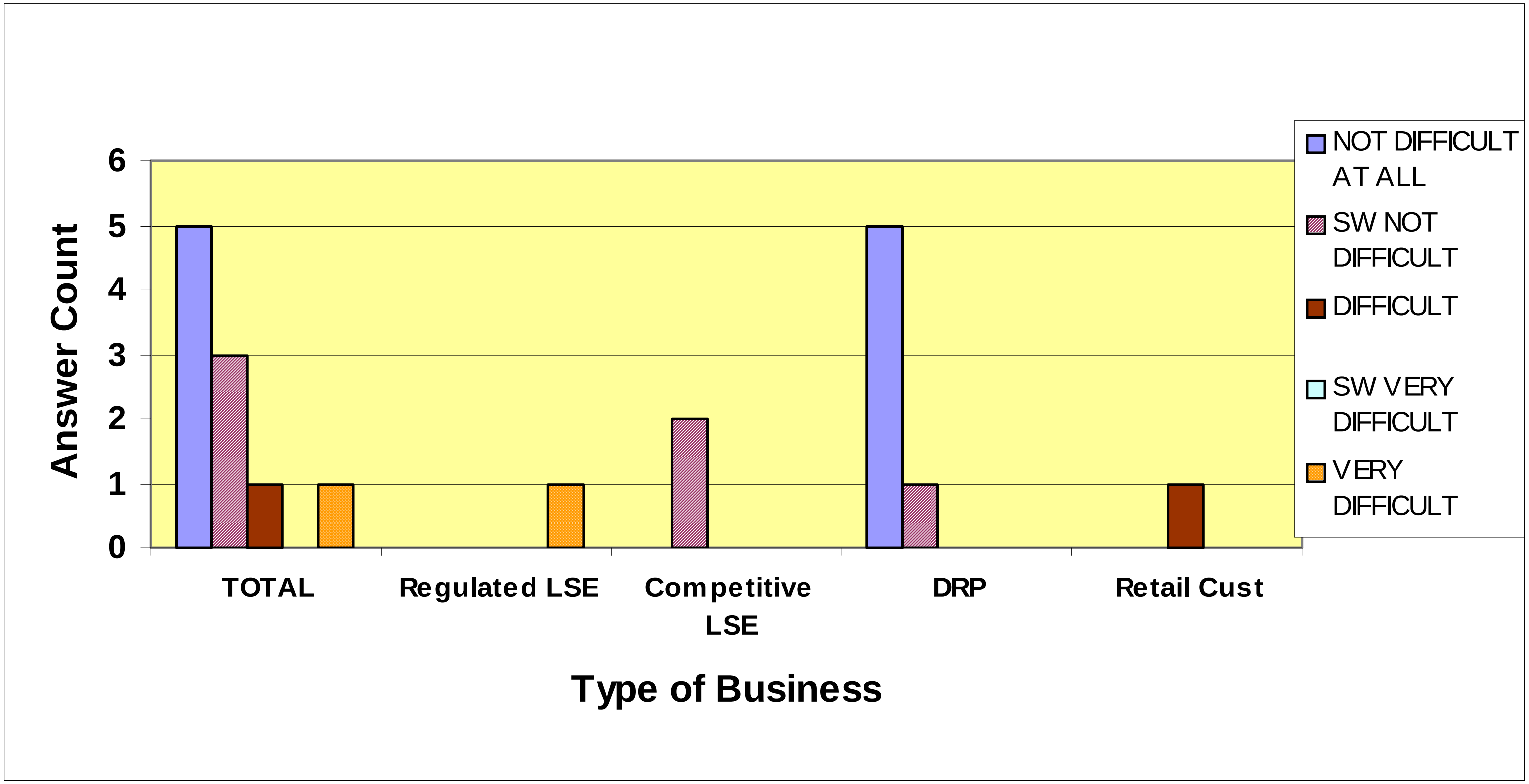

Chart 4.10 Impact of Elimination Energy Payment under ICAP/SCR

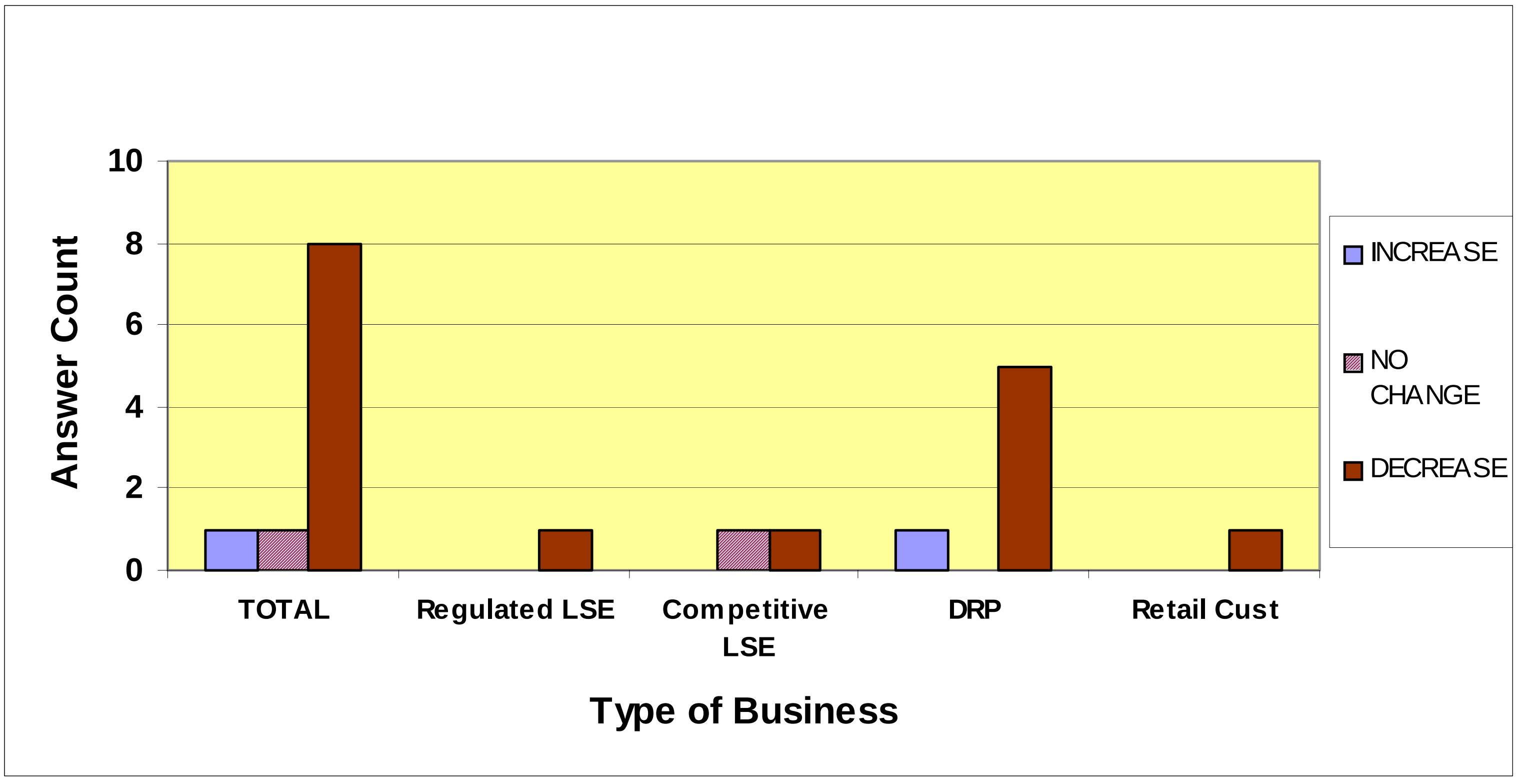

Chart 4.11 Estimated Change in Enrolled ICAP/SCR MW if Energy Payment Eliminated

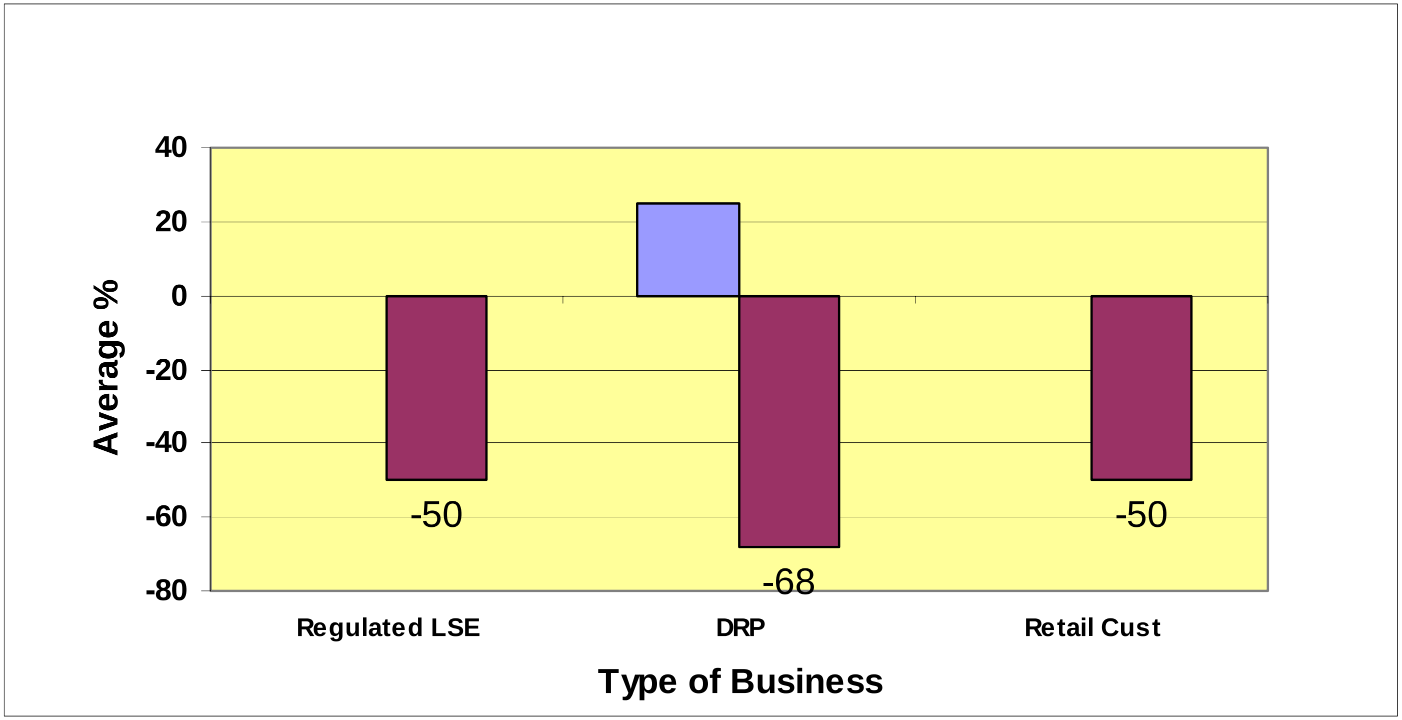

Chart 4.12 ICAP/SCR Curtailment Bid Curves by Years of Experience