

**ISO New England
2002
Demand Response Program Evaluation
Final Report**

Prepared by the Townsley Consulting Group

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**ISO New England
Demand Response Program
Evaluation**

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EXECUTIVE SUMMARY

This report contains an independent evaluation conducted by the Townsley Consulting Group of the Demand Response Program implemented and operated by the Independent System Operator of New England (ISO New England) from the period June through September 2002. The evaluation effort was conducted to assess the programs' overall effectiveness in furthering the development and integration of demand response resources into the wholesale electricity market process and to document both the lessons learned and stakeholder perceptions of the programs' operation. Recommendations were formulated to enhance the future deployment potential for Demand Response resources within New England and to improve the programs' future effectiveness. The recommendations were developed in the following areas based on the evaluation's findings:

- Policy
- Program Design
- Marketing (and end-user participant recruitment), and,
- Program Administration

The Demand Response initiatives implemented by ISO New England in 2002 were an evolution of a Demand Response resource development effort begun in the 2000-2001 timeframe. In June 2002, ISO New England began the operation of two distinct demand response programs:

- A Demand Response Program (Class 1). The Class 1 program required mandatory interruptions from participants when either one of two conditions exist:
 - During NEPOOL Operating Procedure 4 (NOP 4), when ten-minute operating reserve is deficient.
 - When a contingency loss occurs and the ten-minute operating reserve will not be restored in 30 minutes.
- A Price Response Program (Class 2). The Class 2 program called for voluntary participant reductions when the forecasted market hourly energy-clearing price (ECP) as produced from the Unit Commitment Schedule exceeded \$100 per MWh.

In 2002, the magnitude of the total amount of curtailable load enrolled in the ISO's Demand Response Programs (DRP) increased to approximately 190 MW from a total enrollment of 27 MW in 2001. Nearly 80 percent of the 2002 curtailable load enrolled was recruited in Connecticut where the ISO issued an emergency supplemental Demand Response request for proposal and the Connecticut Department of Public Utility control authorized distribution companies to offer a substantial array of enrollment enabling services and also significantly increased the Class 1 incentive payments by \$20,000 per MW-Month.

During the period between June through September 2002, twelve Class 2 events were called. No Class 1 events were called in 2002; however, the ISO's analysis indicates that the presence of Class 1 load in Southwestern Connecticut provided insurance against 78 MW of forced load shedding for a 17-hour period.

The evaluation study consisted of the following elements of data collection and analysis:

- A comprehensive examination of the benefits and costs of the 2002 DRP from a Total Resource economic framework including:
 - An independent (first year) Benefit Cost Analysis (BCA) assessment for the Class 1 and Class 2 Programs.
 - An analysis of the geographical variations in BCA results, i.e., Southwestern Connecticut (SWCT), Northeastern Massachusetts (NEMA)/Boston, etc.
 - Sensitivity analyses of key BCA drivers to ascertain how changes in program operation and design could improve DRP economics.
 - An examination of the potential impact on DRP economics of Standardized Market Design as it pertains to variations in energy related benefits.
 - An assessment of the potential impact of DR on the energy-clearing price.
- A retail customer participant survey was conducted to ascertain their level of satisfaction with various program process elements.
- Surveys were conducted of various stakeholder groups such as state Public Utility Commission (PUC) staffs, distribution companies, etc., to obtain their impressions of the 2002 DRP initiative.
- Process interviews were conducted with selected ISO staff members and other DRP support concerns to follow-up on program administration issues that arose during the course of the evaluation effort.

The major findings of the evaluation were:

Benefit Cost Analysis

A careful assessment of the Demand Response program benefits was conducted utilizing a "Total Resource" economic framework (which is the policy criteria traditionally used by most New England state PUCs to measure the relative economic efficiency of alternative energy and demand resource options). The results of the BCA revealed the following for the ISO's 2002 DRP initiatives:

- The 2002 costs of the Class 1 (reliability) program exceeded the 2002 benefits on a region-wide basis. The major reason for this outcome is that neither the Thirty Minute Operating Reserve (TMOR) nor the potential to receive an Installed Capacity Credit (ICAP) provided sufficient benefits to offset first year infrastructure costs and the end-user load curtailment incentive payments.

Hopefully, much of the first year infrastructure costs, i.e., metering, communication equipment, and other end-user site preparations costs, would also provide DR resource benefits in future years and, therefore, improve program cost effectiveness. The Class 1 program first-year benefits and costs nearly broke-even in SWCT where an average cost of the reliability benefit of \$ 47 per kW-Month was established through the emergency supplemental Demand Response RFP process. The Class 1 program in SWCT was cost effective in SWCT at the RFP's marginal cost of reliability, i.e., \$63 per kW-Month.

- In SWCT, the cost for the Class 1 program was calculated to be approximately \$11,200 per kWh, which falls well within the \$4,000 to \$20,000 range established for the Value of Lost Load (VOLL) at the end-user level referenced in other published studies and is consistent with information developed in the participants study.
- Similarly, the 2002 costs of the Class 2 (price response) program exceeded 2002 benefits on a region-wide basis for the following reasons:
 - The incentives paid to end-users for their curtailment actions were higher than should be required because current retail pricing (and supply contracting) mechanisms, i.e., Standard Offer, Supplier of Last Resort Service, regulated service, etc., form a significant barrier to the direct flow of benefits created by load curtailment actions from suppliers to end-use customers.
 - On average, only about 9 percent of the enrolled load responded to a Class 2 load response event.
 - The hourly threshold of \$100 per MWh for calling a Class 2 event limited the opportunity for additional price responsive load curtailment to be realized.
- The total congestion costs for the SWCT and NEMA/Boston areas for 2002 indicates that the number of hours of operation needed to make the price response program cost effective drop quite substantially making it a more cost effective resource option under a Locational Marginal (Energy) Pricing (LMP) regime.
- Our review of supply resource bidding data for selected days indicated that substantial increases (in excess of 200 MW) in the magnitude of enrolled Class 2 curtailable loads would be needed to create any significant wholesale market Energy Clearing Price (ECP) reductions. The analysis also provided indications

that employing price caps on ECP of \$1,000 MWh nullified any impact that a Class 2 resource could have on price spike mitigation.

Participant Survey

A survey (see Attachment A) was sent to all participants in the ISO's 2002 Demand Response programs. Approximately 17 percent of this population responded to the survey.

The objectives of the survey were to:

- Assess participant satisfaction with various program process elements,
- Determine how participants responded operationally,
- Identify attributes of their operations and decision making processes,
- Assess the value of various marketing and communication techniques, and
- Determine participant potential interest in future program features.

Some of the survey results indicate the following:

- About three quarters of the respondents indicated an overall satisfaction with the 2002 Demand Response program. However, approximately forty percent rated the settlement process fair to poor. Eighty four percent indicated that they plan to enroll again in 2003.
- Over two thirds of the respondents would prefer to receive program information directly from ISO New England. A similar number of respondents attended an informational meeting and found it useful.
- Over 80 percent found the program's rules understandable.
- Sixty percent indicated that they did not monitor the ISO's price forecast. Note, this observation was confirmed by examining the hourly customer response data, which indicated most customers completed their load curtailment activities before the ECP had achieved its maximum value.
- Nearly two thirds of the Class 2 respondents indicated they did not receive a load response event notice in time to participate in one or more events. Most respondents indicated they would prefer to receive event notices very early in the day.
- Approximately three quarters of the respondents indicated no loss of amenity as a result of program participation and about two thirds indicated neither an increase in costs nor a loss of operating revenues from program participation.

- In response to queries about the desirability of future program features, over seventy percent of the respondents rated incentives or financial assistance to support load management infrastructure investment as essential, highly desirable, or desirable. A similar number indicated that free facility load management assessments as desirable. A majority of the respondents indicated that future program features such as on-site generator licensing assistance and multi-year payment guarantees would be desirable.

Stakeholder Surveys

Stakeholder surveys were conducted to solicit stakeholder feedback on their perception of the ISO's 2002 Demand Response Program (DRP) and on the issues that may affect the future development of DR resources in New England. The most robust responses came from the state Public Utility Commission (PUC) staffs and the distribution company staffs who supported the 2002 program implementation.

Highlights of In-Person Interviews with Public Utility Commission Staff

- All felt that power supply issues were a priority for their state, but not all thought that Demand Response was a high priority.

Most PUC staffs did not see the 2002 program as successful based on:

- The amount of enrolled load,
 - Program start-up problems (i.e., late rollout, customer notification, settlement problems), and
 - Class 1 resource not tested.
- All felt that the ISO was primarily responsible for reliability within the standard market zones.
 - Satisfaction with the distribution companies' efforts in the marketing and communicating the benefits of Demand Response range from excellent to unreliable.
 - Regional barriers to Demand Response identified:
 - Not easily understood by customers. (Note: The perceptions held by some PUC staffs regarding how readily understandable the program rules and procedures were is different from most of the feedback received from program participants who responded to the TCG participant survey),
 - Lack of technical support for customers,
 - Incentive payments too low, and,
 - An absence of residential and small commercial and industrial customer aggregation.

- Not much optimism was expressed for (retail) pricing reforms that would be helpful to Demand Response by attaining a greater alignment of wholesale and retail pricing.
- Most did not see a significant role for the PUC's in communicating to end-users about Demand Response benefits, citing financial and people resource constraints.
- Demand Response recommendations offered for the future included:
 - More specific goal setting for Demand Response programs, i.e., the amount of enrolled load,
 - Identification of Demand Response resources needed to mitigate sharp supply curve price increases,
 - Greater parity in market pricing between supply and demand resources, and,
 - The creation of an ISO/NEPOOL standing committee on Demand Resources and other related end-user customer issues that is equivalent in stature and resources to NEPOOL's Reliability and Markets Committees.

Distribution Companies Survey Highlights

The New England distribution companies that supported the 2002 Demand Response initiative were given the opportunity to either participate in a group discussion on their experiences, respond to an email survey, or both. Feedback and comments received from the distribution companies included the following:

- All respondents indicated that power supply issues were a high priority for them. One company reported that it was attempting to target Demand Response resources to reduce load near substations with reliability concerns.
- Concerns expressed about the 2002 program entailed:
 - Low level of sign up,
 - Low payments to customers,
 - The low value of the ICAP credit,
 - Problems associated with establishing the end-user baseline measurement level, and other settlement related problems, and
 - Confusion about end-user activation status.
- All respondents felt the ISO has the overall responsibility for zonal reliability.
- No respondent indicated they planned to do anything differently regarding program marketing or communications in 2003.
- Problems expressed in the marketing of the 2002 program included:
 - Customer confusion about whether to sign up for the Class 1 or Class 2 program,

- Difficulties in explaining ICAP and TMOR to end-users, and,
- The enrollment of modest load reduction commitments on the part of customers as an incremental step in learning more about the program to gain access to program incentives and infrastructure upgrades.
- Some of the companies felt that the ISO provided insufficient administrative support to the program in 2002 and should outsource the program administration function.
- Recommendations made by the distribution companies for the future were as follows:
 - Improve the Class 2 event calling process,
 - Enhance the ISO's support to provide faster turn around to customer inquiries and settlement questions,
 - Make greater use of the ISO's website to communicate about frequently asked questions, and other relevant program information, and,
 - Reactivate the ISO's demand response working group.

Business Process Interview Findings

Feedback collected during the evaluation revealed concerns among several stakeholders regarding some facets of the Demand Response Program's (DRP) administration. Those issues included:

- The quality of information residing in the primary customer information database.
- The validity of data utilized in the settlement process.
- The ability of the ISO to respond to and resolve in a timely manner to issues emanating from the enrollment process, event notification, and settlement calculations.

Interviews were conducted with ISO staff and others involved in supporting the 2002 DRP initiative to further illuminate any causal factors related to the concerns expressed by stakeholders. These interviews surfaced several factors that were the likely causes of the concerns expressed by stakeholders. The principal findings of process interviews were as follows:

- The staff assigned to handle initial processing of the NX11c data was probably insufficient to handle the volume, and initially lacked the training necessary to evaluate and properly interpret the information. This resulted in improper information being passed along in the enrollment process and to the primary customer database.

- In late spring of 2002, the ISO implemented a web-based solution to automate and streamline the NX11c enrollment process. As the program enrollment process was well underway, the new customer information database was being populated from the original database as time permitted. This required ISO staff to rely on two separate databases for primary customer information in order to respond to inquiries (both internal and external). Reliance on these separate databases created some confusion on informational content and contributed to business process inefficiencies. In addition, the new web-based enrollment solution initially had some data formatting incompatibilities with the database used for settlement, which went undetected for a short time.
- The information management problems combined with inconsistencies in the end-user Demand Response baseline calculations between the RETX system and the ISO's settlement system precipitated several questions from customers and LSE's on settlement matters. Additionally, the absence at the ISO of well understood protocols for handling inquiries of this nature and a shortage of available staff resources led to long delays (months) in resolving settlement questions.

As a result of the evaluation, some recommendations have been developed in the areas of policy, program design, program marketing, and administration. TCG feels these recommendations could enhance the prospects for additional DR resource development within New England.

Policy Recommendations

Infrastructure costs of the DRP were modest. Even so, the program was not cost effective as measured by the Total Resource Test. One reason for that outcome is the magnitude of the incentive payments required to induce customer DR participation. Since the market benefits achieved through curtailment actions in 2002 were not utilized to fund end-user incentive payments or improve end-user economic benefit from curtailment actions, the incentive payments were larger than would be needed had market benefits from curtailment actions flowed more directly to those who took the curtailment actions.

Several current policies and practices do not allow for a free exchange (or flow) of DR market benefits between retail suppliers and end-use customers for the following reasons:

- Most retail customers receive generation through Standard Offer (SO) or Supplier of Last Resort (SOLR) services, at time-invariant price levels near (or below) nominal wholesale price levels, resulting in few deregulated retail sales of electricity. Many retail customers want electricity price protection, and State legislators and PUCs want them to have that protection. The PUC stakeholder surveys confirmed that, absent some significant market or operational failures, those (retail electricity price) protections would carry on for some time. As a

result, DR resource development will be limited unless some policy remedies can be implemented to correct for these market imperfections.

- Many of the contractual arrangements for aggregation of SO and SOLR supply do not provide any path for SO or SOLR providers to reduce their supply cost risk through bilateral DR contacts with end-users (or their aggregators). This situation is particularly problematic in instances where the jurisdictionally aggregated SO or SOLR service is divided up among several suppliers with no one-to-one relationship between any supplier and individual end-user.

The following SO or SOLR retail jurisdictional contracting arrangements or practices, could better align the flow of price responsive DR benefits between suppliers of that service and end-users:

- Award only one supply contract to provide SO or SOLR services within a defined geographical area such as a county, town, or group of towns. This would give the SO and SOLR energy supplier a clearer picture of their supply cost risk, especially in an LMP framework. Such a contracting strategy could also be designed to encourage potential retail SO or SOLR service providers to publish curtailment procurement terms for customers within the award area as part of their bid. Additionally, such a process would recognize any unique cost of service attributes within the award area and result in clearer definition of resource costs within the award area so that better resource investment decisions could be made.
- At a minimum, align each retail customer with one primary SO or SOLR supplier, so that supplier can directly contract for curtailment services with the retail end-users they serve (or their aggregator) as a electricity supply cost management strategy.
- If the existing market imperfections which impede the direct flow of DR benefits between end-users and retail energy service providers can not be addressed within the retail jurisdictional frame work, particularly for DR price responsive resources, then other temporary measures could be adopted by the FERC to enable the wholesale market system to provide for greater alignment of DR resource costs and benefits. Such temporary mechanisms may be needed on a situational basis until the deregulated retail market for electricity sales can support significantly more bilateral contracting (i.e., more direct benefit sharing) between retail energy service providers (who are better positioned to capture price responsive DR economic benefits) and end-users, therefore reducing the need for external subsidies.

Program Design Recommendations

The following program enhancements are suggested:

Class 1

1. The program's major focus should be on those geographical sub-areas in which system resource constraints are most acute.
2. Payments to curtailment service providers or end-users should be limited by a reasonable estimate of the value of lost load. This should probably be an upper limit on the amount paid through a competitive solicitation irrespective of whether the ISO or some other entity is conducting the resource solicitation
3. Every effort should be made to promote broad-based, i.e., generation (centralized and distributed), DR and energy efficiency resources, energy storage, reactive compensation, etc., participation in a competitive solicitation, which minimizes both barriers to market entry and the present value of the total resource costs. This should have the effect of reducing program cost and increasing the program net benefit

Class 2

1. End-user incentives should be market-based, that is, funded by bilateral arrangements that give end-users the opportunity to manage their load and retail service providers the opportunity to manage their costs in response to the economic value, i.e., the hourly LMP savings that can be expected from load curtailment.
2. DR programs should accordingly be designed to promote innovative retail pricing, including fostering metering and communications infrastructure improvements.
3. Greater emphasis needs to be placed end-user education and training. This would help end-use customers maximize their economic return by curtailing load when the greatest system benefits can be obtained. End-user education also needs to include technical training regarding load management options and strategies.
4. It appears that the cost effectiveness of Class 2 DR can be significantly improved by increasing the hours of program operation. If greater alignment of DR benefit sharing between retail end-users and their service providers, the more flexibility could be provided to end-users by also allowing lower cost hours to qualify as well. The Benefit Cost Analysis indicated that permitting hours of program operation between \$50/MWh and \$100/MWh would substantially improve Class 2 program cost effectiveness, if program costs were to remain constant.
5. If greater alignment of DR costs and benefits can be achieved between end-users and retail service providers, which would reduce or eliminate the need for external incentive payments, then reducing the Class 2 program floor price to

\$50/MWh or ultimately eliminating the floor price (if external incentives are also eliminated) would enable end-users, retail service providers, or curtailment aggregation entities to make market-based DR related decisions.

Program Marketing Recommendations

The participant stakeholder survey provided several suggestions on how program marketing could be improved:

- End-users indicated a strong desire to get more information directly from the ISO in addition to receiving valuable information from distribution companies. Therefore, enrollment could also be improved if the ISO were to open up additional channels of communications with end-users, particularly those who indicated a preference for electronic mail (e-mail).
- The participant survey indicated end-users also seemed to get a lot out of informational meetings and a high percentage of the 2002 participants had attended an informational meeting. This would suggest that enrollment could also be enhanced if the ISO facilitated more meetings with end-users. Such meetings could be utilized both for DRP recruitment and to help educate end-users on how to more effectively participate in the DRP initiatives.
- More end-user support enablers, such as load management site assessments, financing for load management infrastructure investments, onsite generation licensing support, etc., were identified as beneficial enablers in the participants' survey. This finding is also supported by the much higher DRP enrollment results in Connecticut where some of these support services were financed using system benefits funds as approved by the Connecticut DPUC. These end-user enablers could be very useful in those zones facing higher LMP impacts.

Program Administration Recommendations

The results of the stakeholder surveys, the process interviews and the participants' survey all indicate that additional DRP enrollment and growth will require significant increase in the ISO's program administration support capacity. Some of these capacity gains might be accomplished through the maturation of the Internet based enrollment process's accuracy and effectiveness. The new open architecture Internet-Based Communication System (IBCS) through standardization of the baseline calculation methodologies and other enhancements could also improve the ISO's DRP administrative capacity. However, vigilance needs to be exercised to ensure that the implementation of the IBCS open architecture process is managed in such manner – i.e., adequate preoperational testing, etc., – so as to not create new administrative challenges or burdens.

The immaturity of retail market deregulation (i.e., the lack competitive service providers and bilateral DR contracting, etc.) and the uncertainty and the unevenness regarding the availability of jurisdictional resources support for DRP implementation throughout the region, may necessitate the ISO to strongly consider significantly stepping up its DRP field support resources. If DRP enrollment is to increase, then DRP program resources are needed to support several field implementation functions:

- Enabling the program marketing and enrollment processes by targeting and coordinating the available marketing/enabling resources, cooperatively planning and participating in end-user informational meetings, facilitating and coordinating local stakeholder communications.
- Support the DRP implementation and program operational activities through active monitoring of end-user activation, quick identification and resolution of operational problems or bottlenecks, assist with end-user training, to act as a liaison between end-users and ISO program development and customer service staff.

The appropriate amount of DRP field support may vary across retail jurisdictions, depending on the nature of local support available and the level of need for DR resources need within particular zones.

The 2002 program year experience strongly suggests that additional customer service support dedicated to handling the DRP initiatives is needed. Feedback from several sources strongly suggests the ISO's Customer Service function was overwhelmed by the level of DRP related support required in 2002. Additional people resources are needed to actively and aggressively monitor the NX 11c data collection process to ensure the information being provided is accurate and complete and any actions or operational decisions that may be required are handled properly.

Additional customer services resources are also needed to receive and promptly follow on field or end-user generated inquirers. When those raising the questions or concerns do not perceive their issues are being addressed in a responsive manner then (as was the case in 2002) they begin to go outside the ISO's Customer Service organization to seek assistance. This then creates problems for other ISO functions and creates organizational inefficiencies that only exacerbate the DRP's administration challenges.

Another facet of the ISO's program administration that could benefit from additional attention in 2003 is the DRP settlement process. In 2002, the process of settling the DRP accounts was highly integrated into the overall supplier settlement process and handled in a fairly mechanical manner that was seemingly unable to detect some basic problems with data going into and coming out of the settlement process for DRP accounts.

The DRP settlement is both new and somewhat intricate and learning is still ongoing, therefore, relying completely on an automated process for DRP settlement without rigorous quality assurance review by trained individuals risks end-user and stakeholder

confidence. If more people resources within the existing settlement function cannot be efficiently allocated to address this issue, then consideration should be given to handling the DRP settlement process in a separate (and perhaps functionally separated) manner until the activity is more mature.

During the evaluation process, several questions and concerns about the ISO's willingness to dedicate sufficient resources to the DRP's administration were raised by PUC staffs, the distribution companies, and even from competitive providers of DR services who are active in other markets but currently not active in the New England market. One stakeholder made a telling comment to the effect that it was "good" that DRP enrollment was not greater in 2002; otherwise, the program administration (i.e., customer service) problems would have been worse. Some stakeholders indicated they are cautiously watching the ISO's commitment to effective DR program administration and weighing to what degree they are willing to support program out of concern about the risks for end-users and their own standing with those end-users.

CORRECTIVE ACTIONS ALREADY TAKEN OR INITIATED BY ISO-NE

The ISO, in recognition of the issues that were precipitated in the administration of the 2002 DRP, has taken the following corrective actions to date:

- Increased staffing by adding a full-time Demand Response Manager and three full-time program development, analyst, and administration staff.
- Reactivated the Demand Response working group as a clearinghouse for current DRP information and to identify and resolve operational issues.
- Established a more formalized system of business protocols to address:
 - Enrollment/Registration
 - Activation of Assets
 - Utilization of Assets
 - Settlement and Payment
 - Customer Complaints and Disputes
- Prepared specifications and issued development contracts for an open IBCS solution to standardize participant baseline calculations and processing of participant information.

Additional commitment to the follow through on the corrective actions already being implemented should greatly improve the program administrative processes in 2003.

BACKGROUND

A Demand Response pilot effort was initially deployed and tested by the Independent System Operator of New England (ISO New England) from November 2000 to April 2001. The pilot program tested the capability of an internet-based communication system (IBCS) to support the operation, administration, and integration of Demand Response (DR) into the wholesale market system. Fifteen retail customer sites were recruited for the pilot program that included approximately 27 MW of enrolled curtailment load.

Based on the results of the initial pilot effort, ISO New England sought and received permission from the Federal Energy Regulatory Commission (FERC) in May of 2001 to continue to develop and further expand the initial pilot Demand Response Program (DRP). Starting in June of 2001, participants in the expanded program could select to participate in one of two program prototypes:

- A Demand Response Program (Class 1). The Class 1 program required mandatory interruptions from participants when either one of two conditions exist:
 - During NEPOOL Operating Procedure 4 (NOP 4), when ten-minute operating reserve is deficient.
 - When a contingency loss occurs and the ten-minute operating reserve will not be restored in 30 minutes.
- A Price Response Program (Class 2). The Class 2 program called for voluntary participant reductions when the forecasted market hourly energy-clearing price (ECP) as produced from the Unit Commitment Schedule exceeded \$100 per MWh.

As an inducement for customer participation in the DRP, ISO New England offered to pay 100 percent of the IBCS hardware cost for Class 1 program participants and 50 percent for Class 2 participants. During the summer of 2001 over 500 MWh of load was removed from the system supply requirement through operation of the ISO's DRP.

ISO New England continued to expand and evolve the DRP in 2002. The ISO again sought and received approval from the FERC to continue the program from May 2002 to April 2003. The program continued to offer customers a choice between participation in a Demand Response (Class 1) offering and a Price Response (Class 2) offering. Class 1 participants were compensated for mandatory reductions in contracted load (curtailment) by receiving an installed capability (ICAP) credit, a thirty-minute operating reserve (TMOR) payment and the energy-clearing price (ECP) for each curtailed MWh. Installation of the IBCS was required for Class 1 participation. Class 2 participants were compensated at the greater of the ECP or \$100 per MWh for voluntarily curtailed load when the Class 2 program was called upon. Class 2 customers were offered the option of using the IBCS or "low tech" protocol that relied on e-mail notification and did not require the telemetering of real time load data.

A major change in the 2002/2003 DRP was the introduction of “congestion multipliers” to ECP settlement payments for Class 1 and Class 2 DRP participants, based on the additional operational costs incurred by NEPOOL to address transmission congestion. The congestion (cost) multipliers provided a transition mechanism that acted as a proxy for the anticipated impact of locational marginal pricing on local energy supply costs, thereby, more fully recognizing the unique monetary benefits of load curtailment in the differing geographical areas within NEPOOL. The congestion multipliers utilized for the 2002/2003 program were as follows:

- Southwestern Connecticut Congested Area = 1.61
- NEMA/Boston Congested Area = 2.16
- Vermont Congested Area = 1.99
- All other areas = 1.0

In 2002, significant concerns existed about system reliability in Southwestern Connecticut (SWCT), prompting additional efforts to increase the deployment of demand response in that area, which were directed by both NEPOOL and the Connecticut Department of Public Utility Control (DPUC).

Additionally, ISO New England issued a Request for Proposal (RFP), as described below, to increase the level of Demand Response resources available in SWCT for the period June through September 2002.

“ISO New England Inc. (ISO-NE) solicits proposals to participate in the Load Response Program Southwest Connecticut Emergency Capability Supplement (LRP SWCT ECS). This program seeks to improve system reliability within Southwest Connecticut at times of peak loads, in conjunction with the 2002 ISO-NE Load Response Program (LRP). The RFP seeks proposals for (a) firm customer load reductions through load curtailments and/or emergency generator use, or (b) the temporary installation of new limited use peaking capability in Southwest Connecticut.”

Resource payments to the competitively selected contractors were not limited to those prescribed in the regular DRP. In response to the RFP, the ISO signed contracts for 78 MWs of Class 1 curtailment consisting of approximately 71 MWs of emergency generation and 7 MWs of interruptible load.

To further enable the deployment of Demand Response resources in Connecticut, the DPUC authorized the electric distribution companies to offer additional inducements to customers who would participate in either the Class 1 or Class 2 programs. The additional inducements included:

- Provide the additional engineering support required to facilitate the installation of the ISO’s IBCS solution.
- Incentives to compensate participants for IBCS installation and service costs.

ISO NE 2002 Demand Response Program Evaluation - ATTACHMENT A

- Offer up to \$1500 per site to cover additional “make ready costs” such as wiring, microprocessor connections, etc.
- Incentives to compensate participants for incremental investment in energy management systems (EMS) and emergency generators.
- Provide help desk software training and support.
- Provide participant’s e-mail enabled pagers to supplement ISO notifications.
- Provide free assessments of facility load management potential.
- Supplemental Class 1 payments of \$20,000 per MW-Month (for a 1 hour response and \$10,000 per MW-Month for a 2 hour response).

Enrollment in the 2002 DRP was up significantly from the earlier pilot program activities. Tables I and II below summarize the 2002 DRP enrollments by state.

Table I

Number of Accounts Enrolled							
	<u>CT</u>	<u>MA</u>	<u>ME</u>	<u>NH</u>	<u>RI</u>	<u>VT</u>	<u>Total</u>
Class 1	59	19	0	0	0	1	79
Class 2	<u>56</u>	<u>52</u>	<u>26</u>	<u>1</u>	<u>7</u>	<u>4</u>	<u>146</u>
Total	115	71	26	1	7	5	225

Table II

Amount of Load Enrolled (MW)							
	<u>CT</u>	<u>MA</u>	<u>ME</u>	<u>NH</u>	<u>RI</u>	<u>VT</u>	<u>Total</u>
Class 1	98.1	13.9	-	-	-	0.8	112.8
Class 2	<u>44.3</u>	<u>8.4</u>	<u>20.0</u>	<u>0.1</u>	<u>0.8</u>	<u>1.1</u>	<u>74.7</u>
Total	142.4	22.3	20.0	0.1	0.8	1.9	187.5

STUDY METHODOLOGY

The major objective of the evaluation study was to provide information to planners and policy analysts on the impact, benefits and lessons learned from ISO New England's 2002 DRP initiative that could enhance the future deployment of Demand Response resources.

The components of the evaluation encompass:

- A comprehensive examination of the benefits and costs of the 2002 DRP from a Total Resource economic framework. Issues examined in the Benefit Cost Analysis (BCA) included:
 - The Classification of specific benefits and cost elements such as reserve value, etc., separately for the Class 1 and Class 2 programs.
 - An independent BCA assessment for the Class 1 and Class 2 Programs.
 - An analysis of the geographical variations in BCA results, i.e., SWCT, NEMA/Boston, etc.
 - Sensitivity analyses of key BCA drivers to ascertain how changes in program operation and design could improve DRP economics.
 - An examination of the potential impact on DRP economics of Standardized Market Design as it pertains to variations in energy related benefits.
 - An assessment of the potential impact of DR on the energy-clearing price.
- A retail customer participant survey was conducted to ascertain: their level of satisfaction with various program process elements; how they responded operationally; attributes of their operations and decision making processes; the value of various marketing and communication techniques; and their potential interest in future program features.
- Survey were conducted of various stakeholder groups such as: state Public Utility Commission (PUC) staffs, Distribution companies, etc., to obtain their impressions of the 2002 DRP initiative, their sense of barriers or other impediments to the deployment of Demand Response resources, and their recommendations for future program enhancements.
- Process interviews were conducted with selected ISO staff members and other DRP support concerns to follow-up on issues that arose during the course of the evaluation effort related to stakeholder satisfaction with key program business processes.

FINDINGS/FACTS

BENEFIT-COST ANALYSIS

TCG developed a methodological framework for the benefit-cost analysis (BCA) of the 2002 ISO-NE Demand Response Program (DRP) that is described below.

Objectives

The primary objective of the benefit-cost analysis (BCA) was the quantification of the benefits and costs of the 2002 ISO-NE Demand Response Program (DRP). The comparison of benefits and costs provided an assessment of the effectiveness of resources deployed by the ISO-NE, regulated utilities, and end-users to promote and enable demand response in New England. The analysis paid particular attention to Southwestern Connecticut (SWCT) and Boston, where electric generation resources and energy delivery infrastructure limitations have raised concerns about the reliability and cost of electric power delivery. The results of the analysis should provide useful information concerning future program refinements that could enhance the economic efficiency of resources deployed to enable demand response.

Scope

The analysis addressed the cost-effectiveness of investments to enable demand response by all Class 1 and Class 2 participants in the 2002 ISO-NE DRP. In addition to pure load curtailment (i.e., time-specific reduction in overall electricity consumption), the analysis included investments in self-generation to enable demand response, but not investments in stand-alone generation.

Benefit-Cost Test

The analysis employed the Total Resource Test of cost-effectiveness, which attempts to account for all reasonably quantifiable incremental costs and benefits associated with the program. This test has been endorsed by a number of state regulatory commissions as a guideline for utilities to employ as a measure of efficient resource allocation.

Program Costs

The program costs that were considered and quantified in the BCA analysis included:

- Direct ISO and utility costs,
- End-user equipment rebates,
- Direct payments to end-users,

- End-user incremental investments in load management infrastructure,
- End-user incremental investments in self-generation, and,
- End-user operational costs associated with load curtailment or load shifting.

Program Benefits

The following general guidelines were applied to the formulation of program benefits:

- When there was significant uncertainty in the best way to quantify the value, the analysis bracketed key parameters with two alternatives to reflect the range of uncertainty.
- Clear distinctions were drawn between the different components of value – i.e., energy, capacity, and reliability – as these variously apply to different types of demand response, e.g., Class 1 vs. Class 2.
- Geographical differences in value were estimated when believed to be significant.
- The best estimate of value was employed, even if it conflicted with the prevailing market price, if there was reason to believe that the latter value did not accurately reflect the benefit.
- Functional equivalence, as opposed to technical equivalence, was the guiding principle in the estimation of the avoided costs of energy, generation capacity, and transmission and distribution capacity associated with DR
- Because program investments in end-user education and infrastructure enable DR in future years, future benefits were considered in the analysis.

The following benefits were considered and quantified for inclusion in the analysis:

- *Energy Benefits* were quantified in terms of the hourly market-clearing price of energy. When energy uplift costs had been incurred to manage congestion, the energy-clearing price was modified to reflect these congestion costs.
- *Capacity Benefits* were quantified in terms of the ISO-NE Installed capability (ICAP) Deficiency Charge. (Bilateral contract prices for ICAP were not available for use in this analysis.)
- *Reliability Benefits* were quantified in terms of the avoided cost of power supply and delivery investments required to maintain system reliability.
- *Transmission and Distribution Benefits* were quantified in terms of the avoided cost of investments required to deliver energy within the ISO-NE control area.

Geographical differences in the value of demand response were recognized as follows:

- A proxy for the locational market clearing price of energy was calculated in terms of the Reliability Must Run (RMR) contract costs of generators, which are scheduled to operate out of economic merit order, that are located in the same area as the DR being evaluated.

- The reliability benefits associated with DR in SWCT were equated to the avoided cost of temporary stand-alone generation and other resources procured through the 2002 ISO-NE Emergency Capability Supplement (ECS) program.
- Zonal differences in transmission and distribution (T&D) benefits were quantified in terms of the marginal T&D costs employed by electric distribution companies to assess the corresponding benefits of energy efficiency programs.

Class 1 and Class 2 program benefits were differentiated as follows:

<u>Benefit</u>	<u>Class 1</u>	<u>Class 2</u>
Energy		X
Capacity		X
Reliability	X	
T&D		X

Class 2 DR did not qualify for a reliability benefit because Class 2 participants were under no obligation to respond during system emergency conditions. Class 1 DR did not qualify for energy, capacity and T&D benefits because Class 1 participants were never called upon to curtail load in year 2002. Because Class 1 DR resources were obliged to respond during system emergency conditions, they qualified for a reliability benefit. Had Class 1 resources been dispatched in 2002, then they would have qualified for energy, capacity, and T&D benefits associated with the hours in which they were dispatched to reduce system or zonal loads.

CLASS 1 ISO-NE DEMAND RESPONSE PROGRAM BCA DATA AND RESULTS

Program Costs

The following list summarizes the specific program costs and data sources used to analyze the BCA of the Class 1 DRP:

ISO NE 2002 Demand Response Program Evaluation - ATTACHMENT A

<u>ISO Payments – Metering</u> ¹	ISO payments for RETX system costs
<u>ISO Payments – TMOR</u> ¹	ISO payments for Thirty Minute Operating Reserve (TMOR)
<u>ISO Payments – ECS</u> ¹	ISO supplemental payments for Class 1 resources in SWCT
<u>Utility Incentives - Site Preparation</u> ²	Utility payments for end-user site preparation
<u>Utility Supplemental Payments</u> ²	Utility supplemental payments for Class 1 resources in SWCT
<u>End-User Costs</u> ³	End-user costs in addition to ISO/Utility reimbursements

Program Benefits

<u>TMOR kW (Jun-Sep)</u> ¹	Average summer monthly kW qualified for TMOR payments
<u>SWCT Supplemental Reliability</u>	Monthly TMOR kW times monthly ECS payments/kW (This applied only to SWCT.)
<u>TMOR</u>	ISO payments for Thirty Minute Operating Reserve (TMOR)

Benefit Cost Analysis Results

Table 1 presents the results of the Class 1 BCA separately for New England (NE), including SWCT, SWCT, and NE excluding SWCT. No Class 1 resources were available in the NEMA-Boston sub-area during the summer months.

(Continued)

Table 1. 2002 Class 1 Cost-Benefit Analysis				
	NE	SWCT	non-SWCT	
Program Costs:				
ISO Payments - Metering	\$ 147,030	\$ 88,933	\$ 58,097	
ISO Payments - TMOR	\$ 239,023	\$ 101,444	\$ 137,579	
ISO Payments - ECS	\$ 1,415,812	\$ 1,415,812	\$ -	
Utility Incentives - Site Preparation	\$ 519,400	\$ 284,215	\$ 235,185	
Utility Supplemental Payments	\$ 449,691	\$ 449,691	\$ -	
End-User Costs	\$ -	\$ -	\$ -	
Total	\$ 2,770,956	\$ 2,340,096	\$ 430,861	
Program Benefits:				
TMOR kW (Jun-Sep)	24,048	11,242	12,807	
SWCT Supplemental Reliability	\$ 2,102,874	\$ 2,102,874	\$ -	
TMOR	\$ 239,023	\$ 101,444	\$ 137,579	
Total	\$ 2,341,897	\$ 2,204,318	\$ 137,579	
Program Cost/kW	\$ 115	\$ 208	\$ 34	
Program Benefit/kW	\$ 97	\$ 196	\$ 11	
Program Net Benefit	\$ (429,059)	\$ (135,777)	\$ (293,282)	
Program Benefit/Cost Ratio	0.85	0.94	0.32	
SWCT Supplemental Benefit Sensitivity				
	\$/kW-mo	B/C Ratio	Payback	VOLL
CT Supplement	\$ 20	0.43	2.34	\$ 4,777
Base Case	\$ 47	0.94	1.06	\$ 11,151
ECS Marginal	\$ 63	1.25	0.80	\$ 15,047
Alternative Cost Scenario				
Site Preparation Costs	\$ 666,430	\$ 373,148	\$ 293,282	
Reliability Benefit	\$ 2,341,897	\$ 2,204,318	\$ 137,579	
B/C Ratio	3.51	5.91	0.47	
Cost/kW	\$ 28	\$ 33	\$ 23	
Benefit/kW	\$ 97	\$ 196	\$ 11	

Program Cost/kW and Benefit/kW

Expressed as \$/kW, the costs and benefits for the SWCT sub-area are much higher than NE due to the SWCT ECS and Utility Supplemental payments and the corresponding reliability benefit imputed to Class 1 resources in SWCT.

Program Net Benefit and Benefit/Cost (B/C) Ratio

Class 1 program costs exceeded program benefits for NE as a whole and for SWCT. Because of the much higher value placed on the reliability benefits in SWCT, the cost-effectiveness of the program in SWCT was much higher than in the rest of New England. To better understand the implications of these results for future DRP development and the transition to SMD, the sensitivity of the results to the value of reliability and alternative program cost scenarios were analyzed.

SWCT Supplement Benefit Sensitivity

The base case BCA assumed a value of reliability in SWCT equal to the average monthly ECS payment/kW, i.e., \$47/kW-month. This assumption is based on the implicit value determined by the amount ISO-NE, acting on behalf of NE electric consumers, T&D companies, and market participants, was willing to pay to avoid load shedding in SWCT during the summer of 2002.

A low case scenario was analyzed based on the corresponding amount, \$20/kW-month, that the Connecticut Department of Public Utility Control (the Connecticut electric utility regulatory agency) authorized jurisdictional electric distribution companies to pay customers in SWCT to enroll in the Class 1 program.

A high case scenario was analyzed based on the upper range of the ECS payments, instead of the average, \$63/kW-month. This can be conceptualized as the marginal resource cost up to which ISO-NE was willing to pay for Class 1 resources in SWCT.

The results of the sensitivity analysis are presented in Table 1 in terms of the program B/C Ratio, Payback, and implied Value of Lost Load (VOLL). As one would expect, the B/C Ratio is very sensitive to the value of reliability, ranging from 0.43 to 1.25. By incorporating information regarding the impact of the program on the potential loss of load in SWCT, the three scenarios can be interpreted in terms of the implied value of loss of load in \$/MWh.

According to the ISO-NE report, *Summer 2002 Operations for Southwest Connecticut*, the installation of Class 1 resources through the ECS program provided insurance against the potential for 17 hours of forced load shedding due to transmission line contingencies in SWCT. Therefore, potential outages of 78 MW were avoided over a period of 17 hours (equaling 1,326 MWh) during the summer months. By dividing the total ECS payments by the MWh of avoided loss of load, the implied VOLL is \$11,151/MWh.

The implied values for the three scenarios range from approximately \$5,000/MWh to \$15,000/MWh. Various research studies⁷ have estimated the average VOLL to be in the range of \$4,000/MWh to \$20,000/MWh, with a recent study⁸ finding an average closer to \$30,000/MWh. Thus, the implied VOLL of \$11,151/MWh computed above falls well within the range of this research. In response to a participant survey, which was also part

of our evaluation of the 2002 ISO-NE DR, survey respondents estimated the cost of an unplanned power outage to be between \$5,000-\$17,000/MWh on average depending on the calculation method. Data reported by the Connecticut Business and Industry Association (CBIA) also suggest that the implied values may be in the lower range of customer outage costs. Therefore, it appears that the utility and ISO supplemental payments for SWCT were in line with consumer estimates of the value of lost load.

The program payback is the number of years it will take program benefits to equal program costs and is equal to the inverse of the B/C Ratio. Based on the Sensitivity Analysis, program payback varies between 0.8 to 2.34 years, with the base case scenario being 1.06 years. Therefore, one can conclude that, if the Class 1 resource benefits in SWCT continue for another year, the program will be cost-effective based on the assumed reliability value. This is an important finding in that the 2002 program expenditures funded on-site infrastructure – e.g., metering hardware, software, energy management system (EMS) controls, and end-user education and institutional learning – which enables consumers to control their hourly demand for electricity in an efficient and deliberate manner. This infrastructure can be expected to remain in service to the end-user for several years. Therefore, a more complete analysis of the cost-effectiveness of this program should account for the long-term benefits of DR.

In this regard, it is noteworthy that current forecasts of load, generation, and transmission capacity in SWCT indicate that the current reliability risks will continue for several years until additional resources are in place. The payback calculation does not account for supplemental payments in the second year to provide customers with an incentive to interrupt. However the base case payback in would still be less than 2 years if the program made additional payments of up to \$80/kW in the second year.

Alternative Cost Scenario

The primary objective of the BCA is to elucidate the underlying economics of demand response (DR) in order to inform future DRP planning and policy development by ISO-NE and by state authorities. It is therefore instructive to consider the underlying economic costs and benefits of DR and the corresponding potential net benefit of this resource in a market system that returns the ultimate resource value to the end-use customer. Such an analysis can help policy makers identify the potential benefits to their constituencies of developing wholesale and retail markets that provide electric consumers with the proper incentives to implement DR.

The Alternative Cost Scenario recognizes that the underlying incremental resource cost of DR consists of the metering, EMS control, and customer education costs, collectively labeled Site Preparation Costs. The proxy for Site Preparation Costs included the sum of ISO Metering Payments and the Utility Site Preparation Incentives for hardware and on-site assessments, which, according to the Utilities, covered 100% of such incremental costs in most cases. The program costs not included in the Alternative Cost Scenario represent the actions taken by the ISO and the Utilities to return the economic benefits of

improved reliability in SWCT to the end-user in lieu of an internalized market price incentive. These supplemental payments are intentionally omitted in order to illustrate the magnitude of the difference between the cost of the DR investment and the reliability benefit.

When the value of the Site Preparation Costs in SWCT, equal to \$33/kW, is compared to the base case SWCT reliability benefit of \$196/kW, it is clear that emergency (Class 1) DR in SWCT is a very cost-effective resource. It is also clear, based on the results for NE exclusive of the SWCT sub-area, that the 2002 TMOR benefits are insufficient to sustain investment in DR. The problem that remains is how to internalize these benefits in the form of wholesale and retail market prices that provide end-users with the economic incentive to implement DR.

Unlike the energy commodity, improvement in the reliability of the bulk power system is a public (collective) good, and, as such, cannot be efficiently provided by a market mechanism. Because of the failure of the market to adequately reflect the aggregate consumer willingness to pay for reliability improvements, they must be procured by an entity acting on behalf of all consumers of grid power. For this reason, the ISO will have to continue to charge consumers an amount sufficient to induce the suppliers (end-users) to deliver the improvements required to maintain reliability.

In order to maintain reliability, the issues of (1) the amount the ISO should be willing to pay and (2) the amount that the ISO should have to pay must be addressed. The willingness to pay should bear some resemblance to the aggregate consumer VOLL. The present analysis indicates that the imputed benefits fall within a reasonable range of VOLL, *viz.* \$5,000-\$15,000/MWh. The substantial difference between the imputed benefit and the average infrastructure cost raises the question of whether there are opportunities to reduce the program costs through an expanded procurement process which attracts enough potential supply to bid down the amount paid to suppliers of Class 1 DR.

Many larger customers already have EMS systems and emergency generators in place and the resident expertise to operate them. The last two years of ISO and Utility program activity have further developed the physical and institutional infrastructure to the point where, for many end-users, the basic investments are now sunk costs. As physical and informational barriers which limit entry into the DR market are reduced, the potential supply of DR resources should expand into a more competitive market, which will have the effect of bidding the price down to a lower resource cost. It is likely that DR supply in 2002 was sufficiently constrained to drive the resource price to a level significantly in excess of the average cost of \$33/kW. The potential for such cost reduction can only be determined through future solicitations, which are conducive to broad participation by all potential end-users and a competitive bidding process.

Given the economic margin of a \$33/kW cost vs. a \$196/kW reliability benefit in SWCT, it would seem that even a very conservative end-user would be willing to invest \$33/kW if they could expect a supplemental payment of, say, \$66/kW in return. For example, \$33

to pay for the investment and another \$33 net benefit, yielding a payback of 6 months. This would result in a B/C Ratio of \$196/\$66, approximately 3.0. This is a conservative estimate – i.e., a higher than necessary supplemental payment – because the average required payback reported by survey respondents was around 2 years. However, as discussed above, the best approach would be to engage end-users in a competitive procurement process that will elicit bids reflecting each end-user’s actual opportunity cost.

CLASS 2 ISO-NE DEMAND RESPONSE PROGRAM BCA DATA AND RESULTS

Program Costs

<u>ISO Payments – Metering</u> ¹	ISO payments for RETX system costs
<u>ISO Payments – ECP</u> ¹ Prices (ECP)	ISO payments for interrupted load times Energy Clearing
<u>Utility Incentives - Site Preparation</u> ²	Utility payments for end-user site preparation
<u>Utility Supplemental Payments</u> ² in SWCT	Utility supplemental payments for Class 2 resources
<u>End-User Costs</u> ⁴	End-user costs in addition to ISO/Utility reimbursements

Program Benefits

<u>MWh</u> ¹	Total MWh of interruption
<u>Energy (ECP)</u> ¹	Total ECP savings during hours of interruption
<u>Capacity</u> ⁵ savings	Average monthly Installed Capability (ICAP)
<u>T&D</u> ⁶	Average monthly T&D capacity savings

BCA Results

Table 2 presents the results of the Class 2 BCA. Because of the small number of participants in SWCT and Boston, the results are reported only for New England (NE) as a whole.

Program Net Benefit and Benefit/Cost (B/C) Ratio

Class 2 program costs significantly exceeded program benefits for NE. There are a number of factors that contributed to this outcome, including:

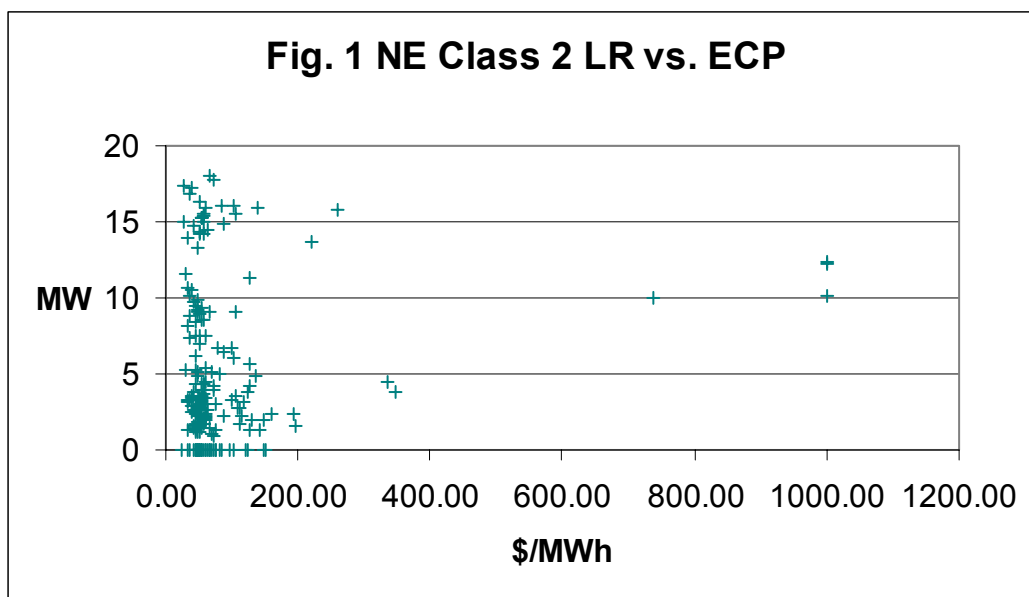
1. Magnitude of Response – There were 73 MW of Class 2 load assets enrolled in the program as of the end of September 2002. The average hourly demand response during the hours in which the program was called was 6.4 MW, the highest hourly value being 18.1 MW. Out of a maximum potential of 11,169

MWh of interruption over 153 event hours during 2002, only 984 MWh, or 9%, were realized.

2. Timing of Response – Figure 1 presents a scatter plot of hourly Demand response against the hourly ECP. The plot indicates a very low correlation between the level of Demand response and ECP. On several days, DR peaked several hours after the ECP and load had peaked. This was partly due to the fact that there were days on which the event window did not open until the ECP and load had already peaked, and also the fact that the survey respondents indicated that they were not monitoring the hourly ECP. The average ECP/MWh interrupted was \$110/MWh.

The ratio of monthly average DR coincident with the system peak to the average non-coincident monthly maximum DR was only 27%. The low coincidence of DR with the monthly system peak resulted in a corresponding reduction in ICAP and T&D benefits.

Table 2. 2002 Class 2 Cost-Benefit Analysis		NE
Program Costs:		
ISO Payments - Metering	\$	36,823
ISO Payments - ECP	\$	135,223
Utility Incentives - Site Preparation	\$	335,600
Utility Supplemental Payments	\$	136
End-User Costs	\$	36,823
Total	\$	544,606
Program Benefits:		
MWh		984
Energy (ECP)	\$	107,850
Capacity (CP 3.7 MW, \$4.87/kW-mo)	\$	71,711
T&D (\$30/kW-yr)	\$	109,333
Total	\$	288,894
Program Cost/MWh	\$	554
Program Benefit/MWh	\$	294
Program Net Benefit	\$	(255,712)
Program Benefit/Cost Ratio		0.53
Energy Benefit Sensitivity		
1) ECP + Congestion	\$	154,513
B/C Ratio		0.62
2) Extended Hours	\$	434,919
B/C Ratio		1.13
3) Increased Response and Extended Hours	\$	1,352,781
B/C Ratio		2.82
Capacity Benefit Sensitivity		
CP 13.8 MW, \$6.66/kW-mo	\$	367,139
B/C Ratio		1.07



3. Number of Hours of Response – In 2002, a total of 53 hours, 46 hours of which were in the summer, had an ECP > \$100/MWh. However, only 32 of the 153 price response event hours had an ECP > \$100/MWh. Additionally, the number of price response event hours in which the ECP was greater than \$50/MWh was 103, compared to 1,045 annually. These data indicate that there is a significant potential to expand the number of price response event hours beyond the 2002 summer event hours. Expanding the number of price response event hours could increase the net benefit of the program because Participants would have the opportunity to curtail load and therefore save energy costs during a much greater portion of the year. Also, given that a lower (e.g., \$50/MWh) price trigger would be, on some hours, closer to, or even below, the participant opportunity cost of curtailment, there would be less chance that the minimum event payments would exceed the real-time ECP, because the magnitude of DR would be reduced at the lower price. What this suggests is that the optimum approach is one in which every hour of the year is a potential “event hour” so that the end-user receives advance notice of the forecasted ECP and has the option to reduce load whenever the ECP is expected to exceed opportunity cost.

4. Energy Payments – As in the Class 1 program, ISO energy payments to participants appear in the analysis as a program cost, but unlike Class 1, there is a market opportunity to eliminate this cost through retail pricing arrangements that provide the end-user with an economic incentive to manage demand. The average payment was \$137/MWh, as compared to the average ECP benefit of \$110/MWh. The payments were higher than the savings because of the minimum guaranteed payment of \$100/MWh and because of the additional amount paid to load assets located in sub-areas with high congestion.

To better understand the implications of these results for future DRP development and the transition to SMD, the sensitivity of the results to the value of energy and capacity benefits and an alternative program benefit-cost scenario were analyzed.

Energy Benefit Sensitivity

The factors listed above raise questions concerning the sensitivity of program cost-effectiveness to the value of energy, the timing and number of hours of the response, and the magnitude of response. Three different scenarios were analyzed:

1. Congestion Costs – At various times, generators are dispatched out of economic merit order by the ISO to maintain system reliability, particularly in zones with transmission congestion. For example, the number of hours during the period January through November 2002 in which this occurred were 3,028 in SWCT, 3,292 in CT (excluding SWCT), and 7,975 in the NEMA Boston areas. The resulting increase in energy supply costs are not reflected in the ECP, but are charged to NEPOOL participants as Congestion Uplift. It is plausible that load reductions in constrained areas could partially alleviate this congestion and thereby reduce such Congestion Uplift costs. Under SMD market rules, the ECP will be localized in the form of a Locational Marginal Price (LMP), which is expected to reflect transmission resource constraints in the corresponding geographical zone. In order to model the potential benefit of avoided congestion costs, the hourly Congestion Uplift costs were divided by the corresponding MWh of generation and added to the ECP for the Class 2 event hours. This has the effect of increasing the hourly-avoided energy cost during the event hours. Using this methodology, the average value increased from \$110/MWh to \$157/MWh.
2. Extended Hours – As noted in Point #3 above, while the Class 2 DR Events, by design, captured a significant portion of the summer hours in which the $ECP > \$100/\text{MWh}$, a lower price threshold could potentially extend the price response into substantially more hours over the course of a calendar year, and stimulate additional investment in on-site infrastructure to enable load management. A scenario was analyzed which assumed the same average MW of DR as occurred in summer, but extended to all hours in which the $ECP > \$50$.
3. Increased Response – As noted in Point #1 above, only 9% of enrolled Class 2 MW were realized on average over the event hours. A scenario was analyzed which assumed an increased average response of 20 MW, or 27% of enrolled assets, in addition to the extended hours assumed in Scenario 2.

The results of the sensitivity analysis in terms of the increased energy benefit and program B/C Ratio resulting from the recognition of Congestion Costs, Extended Hours,

and Increased Response are presented in Table 2 above. Inclusion of the average NE congestion costs increased the energy benefit by 43%, but this was not sufficient to make the program cost-effective for NE as a whole based on 2002 program benefits and costs. On the other hand, by significantly extending the hours and magnitude of the response, the program could be very cost-effective, achieving a B/C Ratio of 2.82. Because the focus of these scenarios was on the value of energy, the capacity benefits were not modified. If the corresponding increase in avoided ICAP and T&D costs were reflected in Scenario 3, then the B/C Ratio would increase accordingly.

The dramatic increase in cost-effectiveness assumes that there is no significant increase in program cost corresponding to the increased benefit. The validity of this assumption is based on the fixed nature of the infrastructure investment and on the ability of the market to provide an incentive that is commensurate with the economic value of the energy savings, as discussed in more detail below.

Capacity Benefit Sensitivity

As noted in Point #2 above, the coincidence of Class 2 DR with the NE monthly peak loads (during event hours) was quite low. A scenario was analyzed which assumed increased coincidence and a higher value of Installed Capability (ICAP). Instead of the average monthly coincident value of 3.7 MW, this scenario assumed an average monthly DR amount of 13.8 MW coincident with the monthly peak. In other words, in this scenario the participants would be able to achieve a coincident DR equal to the non-coincident DR that was achieved in 2002. As in the energy benefit sensitivity analysis, this assumption is based on a scenario in which customers are presented with an appropriate incentive to match the timing of DR with the value of capacity. Note that this still amounts to only 19% of enrolled MW. The ICAP benefit was also increased from the 2002 value of \$4.87/kW-month to the projected 2003 value of \$6.66/kW-month.

The increase in monthly coincidence and ICAP value is sufficient to make the program cost-effective in 2002, without any increase in the number of hours of response. Note that the increase in coincidence would also have the effect of increasing the avoided T&D costs, not reflected in this scenario, which would further increase the B/C Ratio.

Alternative Benefit-Cost Scenario

The primary objective of the BCA is to elucidate the underlying economics of Demand response (DR) in order to inform future DRP planning and policy development by ISO-NE and by state authorities. As in the Class 1 BCA, it is therefore instructive to consider the underlying economic costs and benefits of DR and the corresponding potential net benefit of this resource in a market system that returns the ultimate resource value to the end-use customer. Such an analysis may help policy makers identify the potential benefits to their constituencies of developing wholesale and retail markets that provide electric consumers with the proper incentives to implement DR.

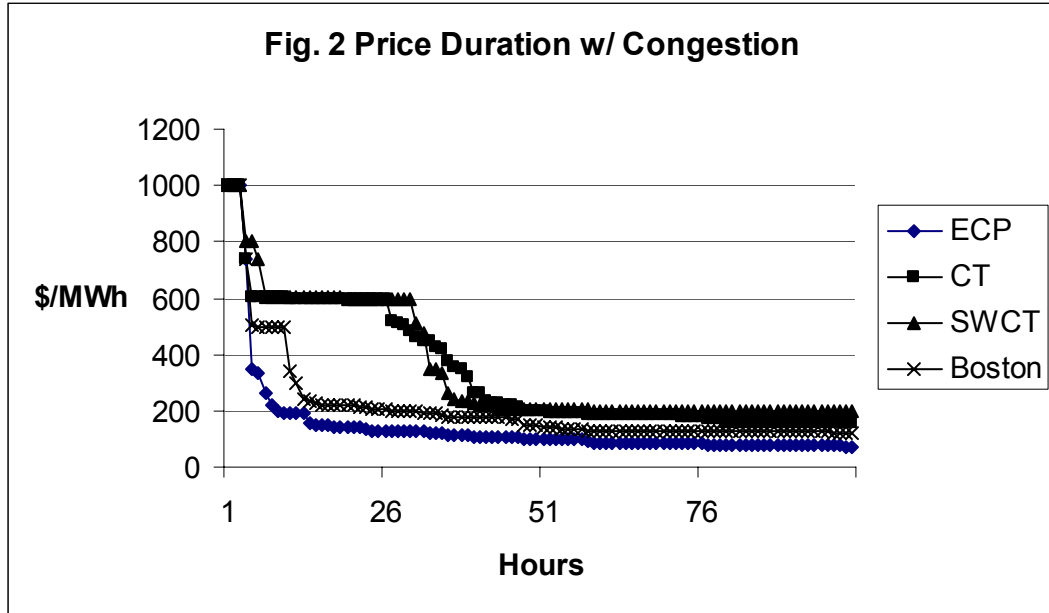
The Alternative Benefit-cost Scenario recognizes that the underlying incremental resource cost of DR consists of the metering, EMS control, and customer education costs, collectively labeled Site Preparation Costs. The proxy for Site Preparation Costs was the sum of ISO Metering Payments and the Utility Site Preparation Incentives for hardware and on-site assessments, as well as any additional costs to the end-user not covered by ISO or Utility payments. The program costs not included in the Alternative Cost Scenario represent the actions taken by the ISO and Utilities to return the economic benefits to the end-user in the form of supplemental payments for energy savings in lieu of an internalized market price incentive.

In contrast to the system reliability benefits imputed to Class 1 DR, discussed above, the energy benefits resulting from price-responsive DR can, in principle, provide the end-user with a market-based incentive to manage load. In a competitive market, in which end-users are informed about DR options and energy suppliers are competing for load, an incentive will exist for the (load-holding) supplier to present the end-user with retail pricing options that either: (1) reduce the supplier's exposure to high spot market prices if short on supply; or (2) increase the supplier's opportunity to sell energy into the spot market during the higher-priced hours. The retail pricing options could take many forms, including setting a threshold price above which the end-user would be exposed to the spot price, or a lower fixed price contract in exchange for supplier-invoked DR, which essentially reduces the risk premium paid by the end-user as an incentive to assume the price risk.

In this market-based scenario, there should be no need for third parties such as the ISO to pay the end-user the LMP for interrupted load, because the LMP savings would be returned via retail pricing arrangements such as those described above. The remaining costs are the economic resource costs to enable Demand response that include the infrastructure costs and any other cost incurred by the end-user. Once the metering and energy management systems are in place, the amount and duration of Demand Response will depend on site-specific parameters such as the facility operating schedule, the amount of critical load, and the expected marginal electric bill reduction as compared to the incremental opportunity cost of foregone consumption each hour. For these reasons, the end-user is in the best position to determine the cost-effective amount and duration of demand response.

The sensitivity analysis indicated that cost-effectiveness depends on the magnitude, duration, and value of demand response. In order to analyze the interaction of these factors, a breakeven analysis was performed to determine the minimum number of hours required to equate the energy benefits to the total Site Preparation Cost of \$409,247 under different combinations of value and magnitude of response. The value of demand response was varied in terms of the impact of congestion costs in CT, SWCT, and the NEMA Boston areas. The NE ECP was increased by the hourly congestion cost/MWh in each area. The resulting price duration curves are presented in Figure 2 for the period January through November 2002.

Figure 2 illustrates that the addition of congestion costs to the hourly NE ECP, as may occur with the advent of LMP, significantly expands the duration of prices greater than \$200/MWh, especially in SWCT and CT. Boston, on the other hand, reflects a much longer duration of prices greater than \$50/MWh (see Table 3). In each area, the minimum cost-effective number of hours was calculated for varying levels of demand response, from 5% to 65% of the enrolled Class 2 assets. The results are presented in Figure 3 and Table 4. Figure 4 illustrates the cost-effective price threshold for each scenario.



Given the assumption that the program infrastructure costs are composed mainly of a fixed investment at each site to enable load control, the results indicate the importance of the magnitude of load interruption, which in turn depends upon the expected return to the end-user for exercising the control option. At 50% response, only 58 hours would be required for the ECP (with no congestion adder) to cover the incremental resource costs. The corresponding price threshold is \$90/MWh.

The potential impact of congestion costs on cost-effectiveness is seen in the SWCT results for the same response level. Only 15 hours of interruption, all hours in which the price (plus congestion) is greater than or equal to \$600/MWh, would be required for first-year program benefits to exceed first-year costs. Even at 20% response, only around 65 hours per year of DR in CT and SWCT could be cost-effective at a price (plus congestion) threshold of \$185-\$200/MWh. In this context, the potential economic benefits of zonal pricing to stimulate cost-effective load control are substantial. The key here is that the market price provides the economic incentive to the end-user to match the magnitude, timing, and duration of curtailment to its economic value, given the end-user's unique operational parameters.

Table 3. Impact of Congestion on Price Duration

	Hours			Total	Average \$/MWh	Period
	>\$200	>\$100	>\$50			
ECP	8	53	1,045	8,760	\$ 35.55	Jan-Dec 2002
Boston	28	493	7,671	7,975	\$ 68.26	Jan-Nov 2002
CT	47	322	1,973	3,392	\$ 44.72	Jan-Nov 2002
SWCT	136	642	2,010	3,028	\$ 47.52	Jan-Nov 2002

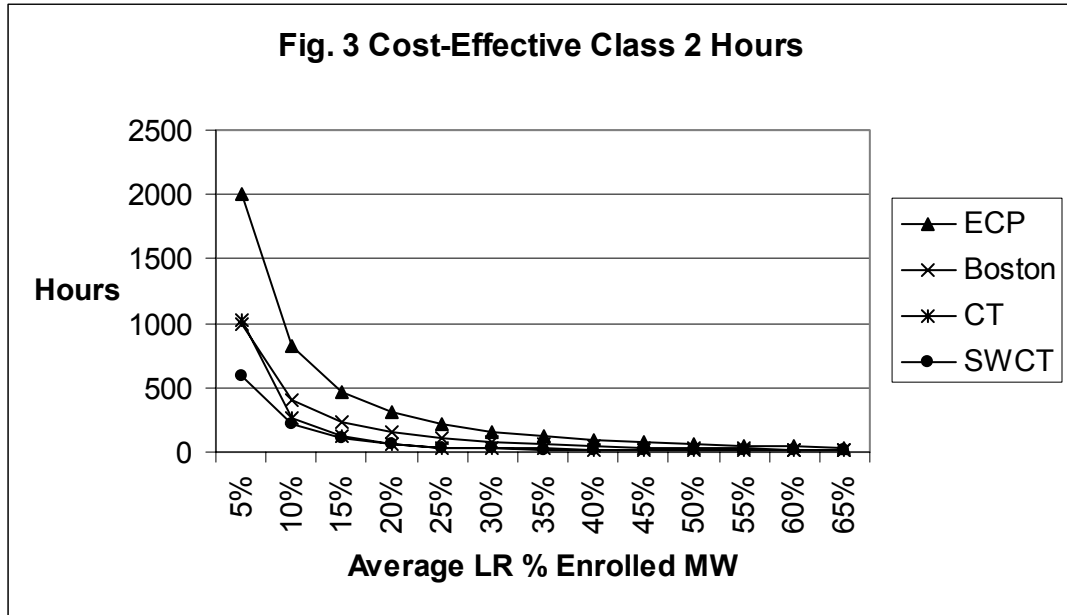
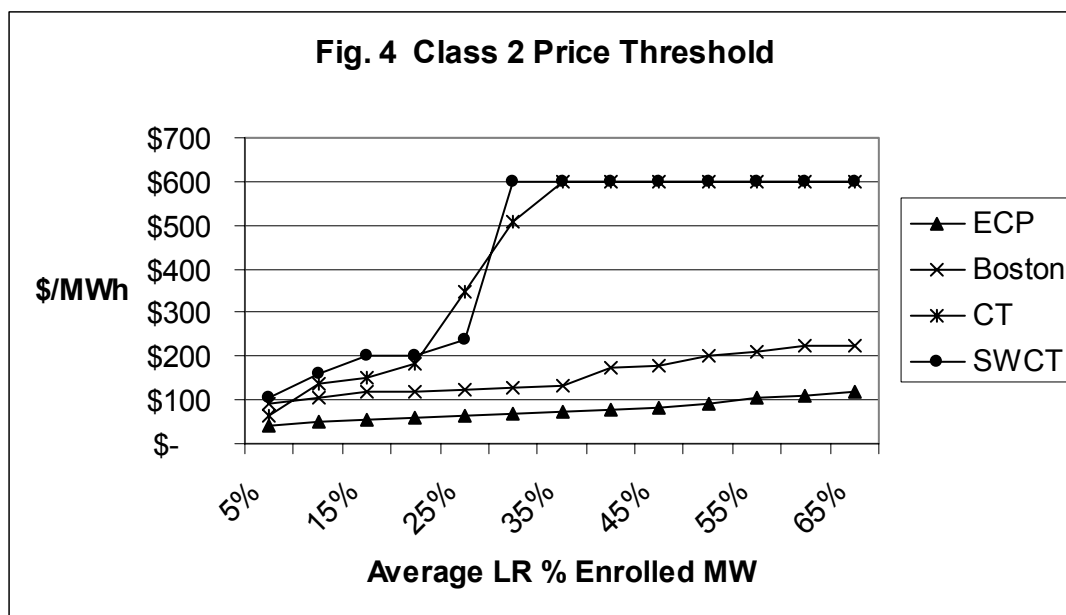


Table 4. Minimum Cost-Effective Hours of LR as % of Enrolled MW

	MW	ECP	Boston	CT	SWCT
5%	4	1999	993	1020	593
10%	7	816	406	257	217
15%	11	468	235	124	111
20%	15	306	156	66	64
25%	18	215	109	38	37
30%	22	158	79	29	28
35%	26	119	59	24	23
40%	29	92	45	21	20
45%	33	72	36	18	17
50%	37	58	29	16	15
55%	40	47	24	14	14
60%	44	39	20	13	12
65%	47	33	17	12	11



The breakeven analysis was focused on the potential for the energy benefits of DR to outweigh the resource costs required to enable end-users to respond to economic incentives to manage their load. The ICAP and T&D benefits were ignored, but would potentially increase in proportion to the average magnitude of hourly response. Of course, as with the energy benefit, a pricing mechanism that communicates the economic value of the avoided capacity and T&D costs is necessary to provide an effective incentive to the end-user without creating additional uplift costs that nullify the benefits. However, given the uncertainties surrounding the economic value of ICAP and avoided T&D costs, it is encouraging to find that there is a great potential for price-responsive load to pay for itself solely on the basis of the energy benefits. Another reason for excluding these other benefits is to allow for the possibility that the Class 2 participants, in particular those outside Connecticut who did not receive supplemental utility incentives for infrastructure investments, experienced additional costs not accounted for in this analysis.

Finally, the breakeven analysis is based on the criterion that the infrastructure investment be paid back in one year by the energy savings. In fact, once the investment is made, price-responsive DR is enabled for the remaining useful life of the metering and load control systems that have been installed either during or prior to program implementation. Since the survey respondents responded that, on average, they require a 2-year payback on such investments, the breakeven criterion of a 1-year payback is conservative.

To summarize, the essential elements of cost-effectiveness are:

1. Response of sufficient magnitude to cover end-user costs,
2. Opportunity to respond during the highest cost hours throughout the year,
3. Recognition of avoided congestion costs, and,
4. Retail prices that provide an effective incentive to manage load.

In fact, the first three of these factors ultimately depend on the fourth, namely the ability of the retail energy market to return the economic benefit to the end-use customer.

ANALYSIS OF THE POTENTIAL PRICE IMPACT OF DEMAND RESPONSE

If the supply curve is sufficiently steep in a neighborhood of the ECP, and the magnitude of the DR is sufficient to clear the market at a lower bid price, then the price of energy can be reduced for all purchasers in the spot market. The magnitude of the savings depends on the magnitude of the price reduction and the amount of energy traded in the spot market. The magnitude of Class 2 DR in 2002 was not large enough to make a significant impact on the ECP, however, the potential impact can be analyzed by examining the supply bids to determine how large a price reduction could have been achieved by a given amount of load reduction.

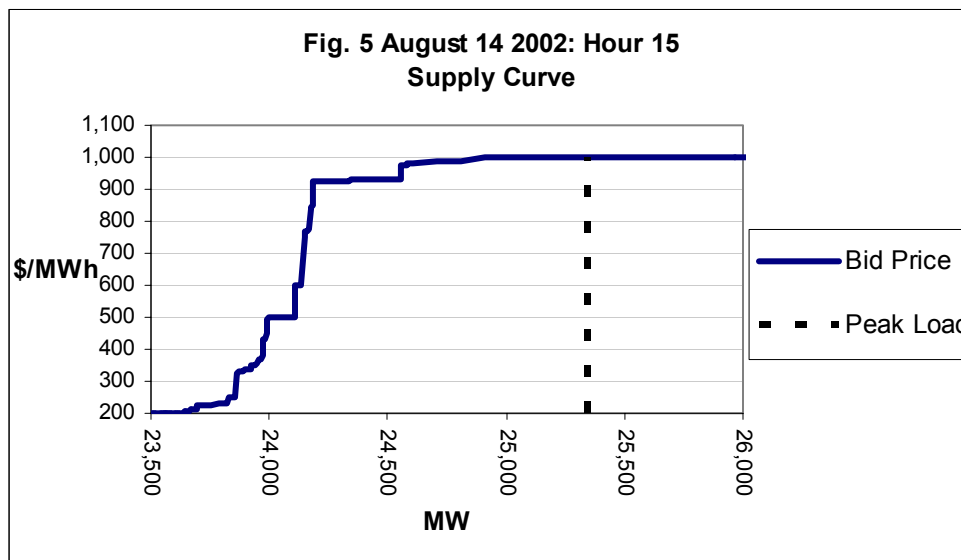
Two Class 2 event days, July 3 and August 14 were selected and analyzed to estimate the potential savings from a hypothetical 200 MW load reduction. The results are presented in Table 5.

Day	Hour	ECP	Lower Bid Price	Price Impact	Spot Market MW	Price Savings
3-Jul	14	\$ 195	\$ 179	\$ 16	6,162	\$ 101,432
3-Jul	15	\$ 194	\$ 179	\$ 15	6,197	\$ 94,381
3-Jul	16	\$ 115	\$ 102	\$ 13	6,248	\$ 83,289
14-Aug	14	\$ 1,000	\$ 1,000	\$ -	6,375	\$ -
14-Aug	15	\$ 1,000	\$ 1,000	\$ -	6,438	\$ -
14-Aug	16	\$ 1,000	\$ 1,000	\$ -	6,615	\$ -

On July 3, a 200 MW decrement in demand would result in a \$16/MWh reduction in the ECP. When this is multiplied by the 6,162 MW traded in the spot market, the total estimated savings is \$101,432. The corresponding results for hours 15 and 16 are \$94,381 and \$83,289, respectively.

On August 14, 2002, the summer peak day, the ECP was capped at \$1000/MWh on hours 14, 15, and 16. Figure 5 indicates that during these hours; the supply curve included several hundred MW of capacity bids capped at \$1000/MW to the left of the peak demand quantity. Therefore, a 200 MW load decrement would have had no effect on the

ECP. This result indicates that, during peak load conditions, DR could potentially play a significant role in price spike mitigation in lieu of a regulated price cap.



CONCLUSIONS

The benefit-cost analysis of the 2002 program supports the following general conclusions concerning the economics of DR:

- It is critical that the BCA framework clearly define the different types of benefits that apply to emergency versus price-responsive resources. Reliability benefits, resulting from the capability to respond in a timely fashion to system contingencies, have a fundamentally different value than voluntary load reductions in response to price signals. Moreover, while the basic costs to enable these resources are similar in nature, i.e., the cost of load management infrastructure, reliability benefits must be procured on behalf of consumers by the ISO, or by the states, whereas price-responsive load would be most efficiently procured through a competitive energy market and appropriate retail pricing options.
- It is important for the BCA framework to recognize that DR benefits, in an LMP framework, can vary dramatically depending on geographical location. This was demonstrated in both the Class 1 and Class 2 analyses. The benefits of Class 1 and Class 2 resources are greatest in SWCT, where resource limitations compromise system reliability and produce significant congestion costs due to the need to dispatch high-cost local generation to maintain system security.

- Because Class 1 resources are a public good, the market cannot be relied upon to reveal consumers' aggregate willingness to pay for improvements in the reliability of the bulk power system. However, the cost-effective limit on investments in these resources can be estimated in terms of the value of lost load. What is most important is that measures be taken to stimulate a broad-based competitive response to future solicitations in order to obtain a competitive price and realize the potentially substantial net benefit of DR.
- The potential benefits of Class 2 resources can best be realized through a competitive supply market in which end-users are offered prices (either fixed or variable) that provide an economic incentive to manage load. This will allow end-users to maximize their return by matching the magnitude, timing, and duration of DR to the highest-price hours throughout the entire calendar year. Geographical price differentiation will also be a significant factor in eliciting DR in those areas that experience high congestion costs.
- DR has the potential to mitigate ECP price spikes, but only if a much larger response is achieved than that achieved in 2002. Administratively determined price caps on the ECP during peak load conditions also limit the benefits of DR on such peak days.

In summary, the future cost-effectiveness of both emergency and price-responsive DR will depend on the extent to which administrative procurement and market mechanisms can be developed that provide an economic incentive to the end-user to manage load. In the case of emergency DR, reliability benefits will still have to be procured by the ISO, but there is an opportunity to significantly reduce the social cost. Price-responsive load, on the other hand, should be achievable in a decentralized competitive energy market via appropriate retail pricing options offered to those end-users who are in a position to economically manage their load.

PROGRAM RECOMMENDATIONS

The following program enhancements are suggested by the foregoing discussion:

Class 1

1. The program focus should be on those geographical sub-areas in which system resource constraints are most acute.
2. Payments should be limited by a reasonable estimate of the value of lost load. This should be an upper limit on the amount paid through a competitive solicitation.

3. Every effort should be made to promote broad-based end-user participation in a competitive solicitation, which minimizes barriers to entry. This should have the effect of reducing program cost and increasing the program net benefit.

Class 2

1. End-user incentives should be market-based, that is, funded by retail pricing arrangements that give customers the opportunity to manage their load in response to the economic value, i.e., the hourly LMP savings that can be expected from load curtailment.
2. Special third-party programs should accordingly be designed to promote innovative retail pricing, including metering and communications infrastructure, and end-user education and technical assistance regarding load management options.
3. Artificial limitations on the scope of price-responsive load management, based on predetermined hours of the year, or a prescribed minimum price threshold, should be avoided in order to allow the end-user maximum discretion in selecting the most economically advantageous parameters of load curtailment at each facility.

REFERENCES

- ¹ Source: ISO New England
- ² Source: Connecticut Light and Power and United Illuminating
- ³ Class 1 End-user costs were assumed to be equal to zero.
- ⁴ Source: ISO New England; Class 2 end-user costs were assumed equal to the ISO payments, which reimbursed participants for 50% of the metering costs.
- ⁵ Source of ICAP deficiency charges: ISO New England
- ⁶ Source of avoided T&D costs: 2003-2004 CL&P/UI Conservation and Load Management Plan p.81 CL&P and UI avoided costs were averaged.
- ⁷ See Steven Stoft (2002), *Power System Economics*, p.112 and Peter Crampton and Jeffrey Lien (2000), *Value of Lost Load*, pp 3-5
- ⁸ See Charles River Associates (2002), *Assessment of the Value of Customer Reliability (VCR)*, p. 6

PARTICIPANT SURVEY

During the fall of 2002, a survey, developed in Microsoft Word, was e-mailed to all participants in the program by Townsley Consulting Group (TCG). Respondents were given the choice of completing the survey in Word and e-mailing it back, confidentially, to TCG, or completing a fax back version of the survey (Appendix A). The objectives of the survey were to:

- Assess participant satisfaction with various program process elements,
- Determine how participants responded operationally,
- Identify attributes of their operations and decision making processes,
- Assess the value of various marketing and communication techniques, and,
- Determine participant potential interest in future program features.

The survey covered eight topics, and allowed the respondent to select answers:

- From pull down menus,
- By selecting check boxes, which in some cases allowed for multiple responses, and,
- Offered sections for unlimited comments.

Results:

The e-mail survey approach for participants worked well. An overall response rate of 17% was achieved. E-mail surveys were received from 38 participants in total, with only two participants choosing the fax version of the survey. This survey approach also allowed for a quick turnaround time for responses with almost half of the surveys returned within two business days.

Although the survey was comprehensive and subsequently relatively long (89 questions), the majority of respondents responded to all of the survey questions.

It is also important to point out that respondents were asked to save the Survey Word document under a unique name, complete the survey and e-mail it back to TCG. As an inducement to respond, participants were offered a \$25 gift certificate for their choice of Home Depot or Staples. Interestingly, almost three fourths of the respondent stated they would be willing to participate in an additional follow-up phone call. Clearly, this survey approach is a viable option for future surveys of business participants – as long as e-mail addresses are known.

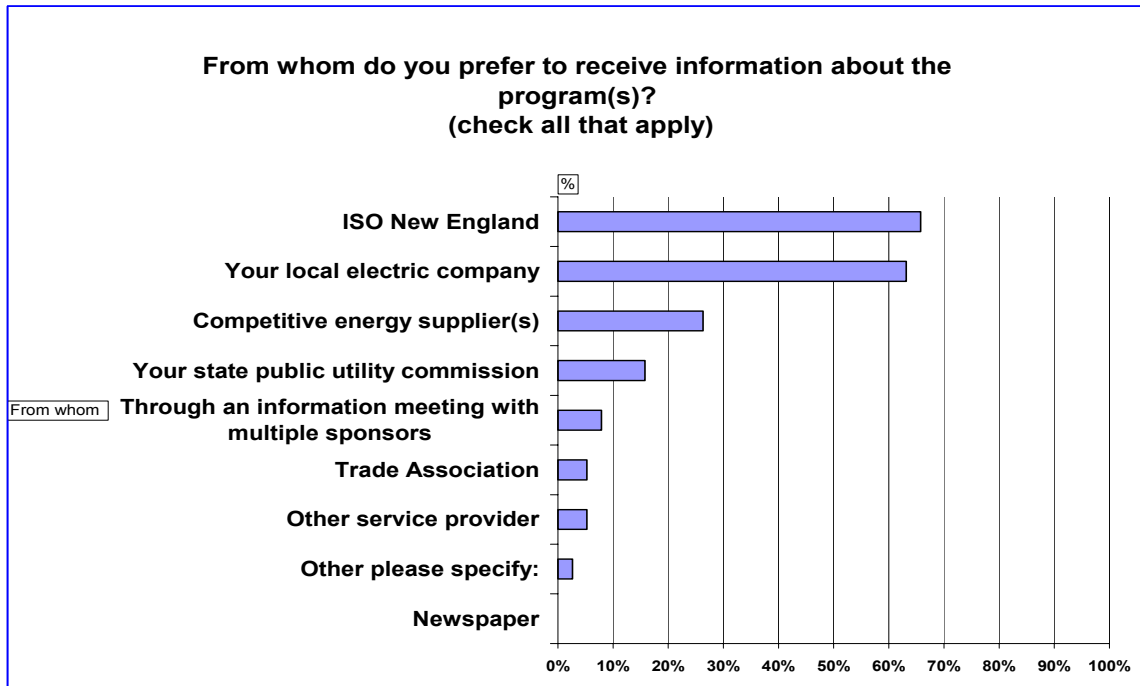
Class 1 (n=13) vs. Class 2 (n=25) survey respondents mirrored the overall population in terms of percent responding (17%). All states in the ISO – NE region are represented in the survey responses except for New Hampshire.

At a 90% confidence level, survey results for the total population of respondents have a precision between $\pm 4\%$ and $\pm 12\%$ based on the number of active DR accounts reported by the ISO to the FERC. The precision for the individual Class 1 and Class 2 programs are somewhat lower with ranges between $\pm 11\%$ and $\pm 21\%$, and $\pm 6\%$ and $\pm 15\%$, respectively.

A discussion of major findings by survey topic is presented below. A tabulation of all questions is contained in the Appendix.

Program Marketing:

The majority (61%) of respondents first heard about the program from their local utility company, with 17% hearing from ISO New England and 11% (all Class 2) from a competitive energy supplier. However, when asked from whom they prefer to receive program information 66% responded ISO New England and 63% said from their local utility company, followed by competitive energy supplier (26%) and state public utility commission (16%).



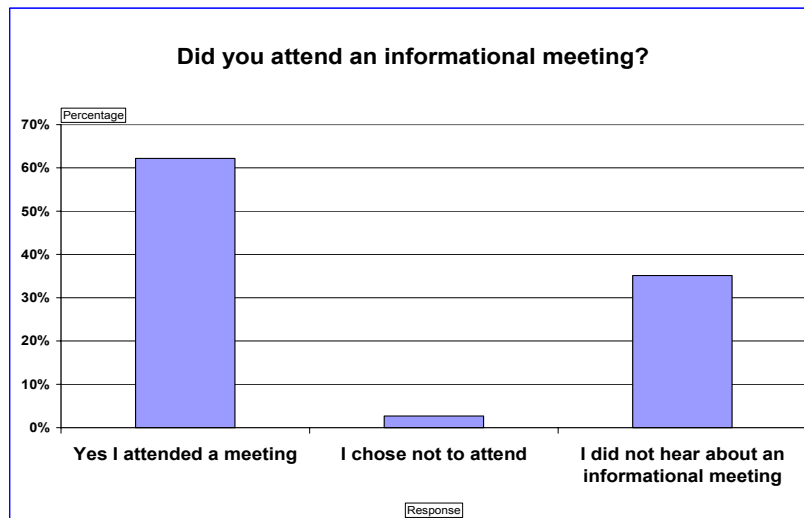
In terms of who or what were most influential in their decision to participate in the program (multiple responses allowed), 75% of respondents were extremely or very influenced to participate by their local utility company. 39% were influenced by ISO – New England. Competitive energy suppliers, however, were not very influential with 74% of survey responses stating they were not influential at all. Trade associations and the news media were also not influential.

Respondents' top three reasons for participating were:

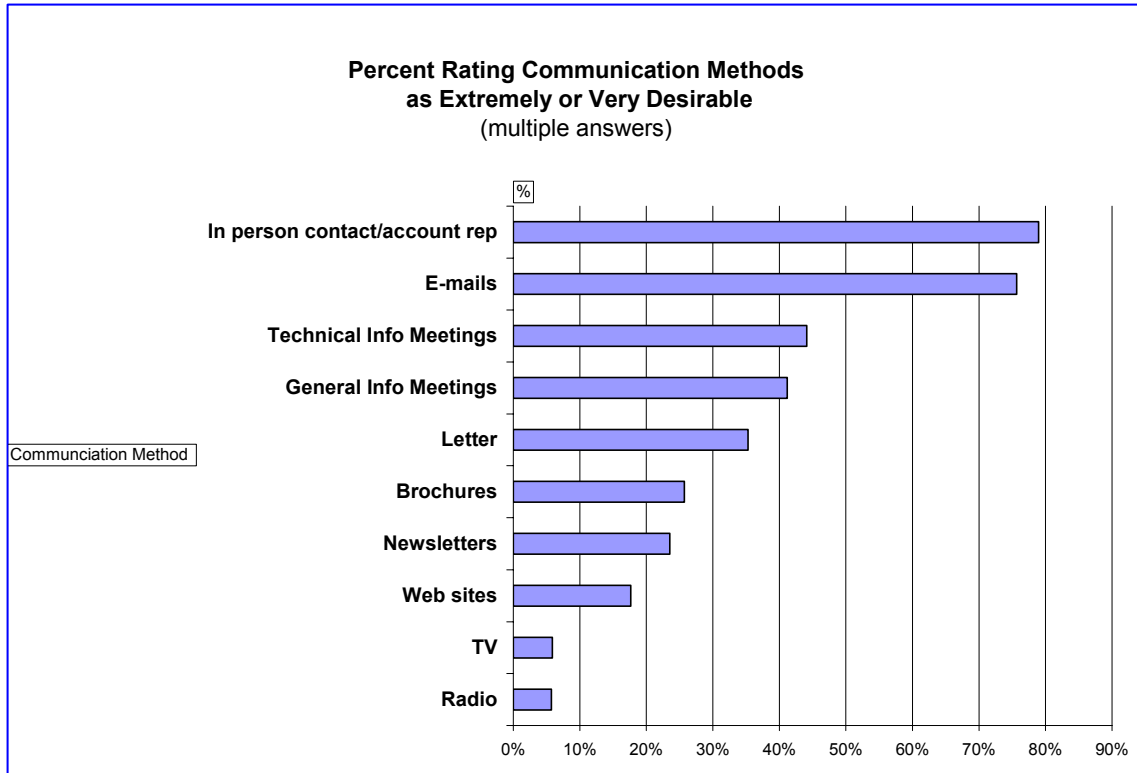
- #1 - to receive payment of load reduction,
- #2 - avoid blackouts, and,
- #3 - corporate responsibility.

The survey responses showed that the key decision maker regarding participation in the program was at the local level vs. corporate, with responsibilities distributed across different functions.

Informational meeting rated highly, with 83% of the respondents who had attended an informational meeting rating the meeting either extremely or very useful. However, 35% of respondents did not hear about the informational meeting.



Although respondents liked informational meetings, their preferred communication methods were in person contact from an account rep (79%) and e-mails (76%). Radio, TV, and bill stuffers were undesirable methods.



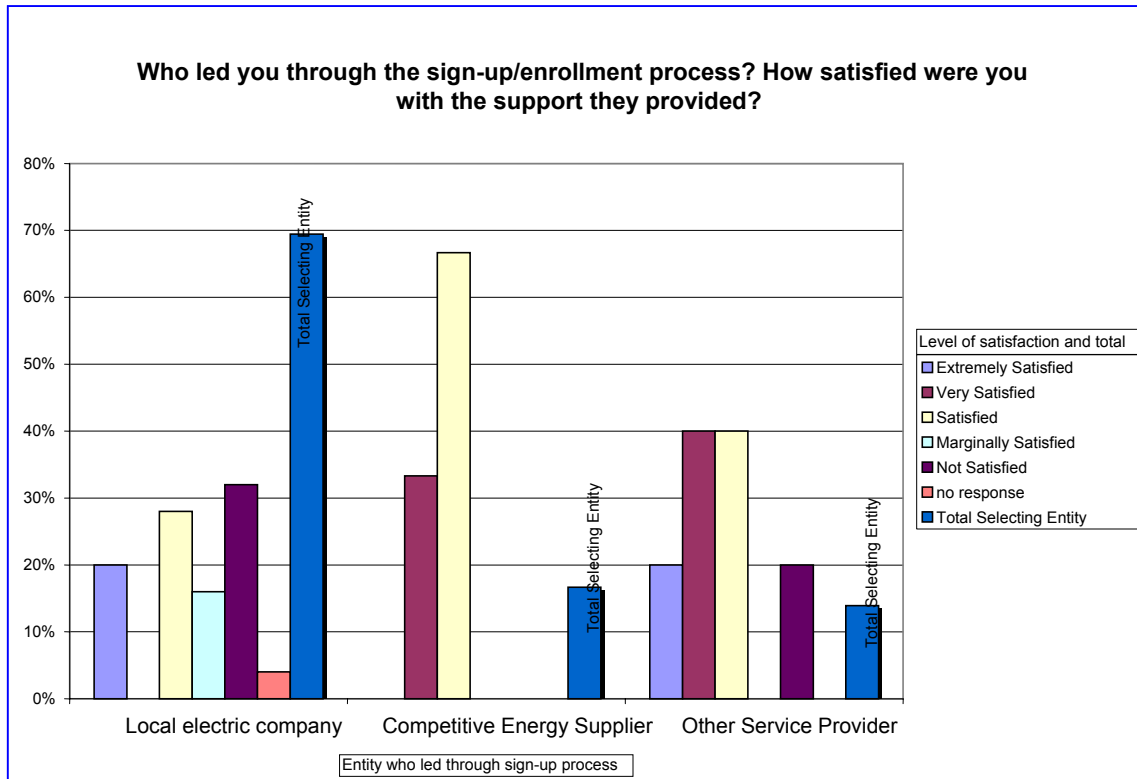
The marketing material itself was rated highly with the majority of respondents rating the marketing material received as either good or excellent. Approximately half of the respondents either did not recall receiving information about both programs or only received material about one program. In general, the marketing material rated above average for a variety of attributes, with an average of 3.7 out of 5 for usefulness in helping to make a decision.

Average	Rating of Marketing Material by Attributes (scale of 1 to 5, with 5 being the highest)
3.4	a. Provided key program information in a straightforward and easy to understand manner
3.5	b. Provided just the right amount of information about each program
3.5	c. Program benefits were clearly noted
3.5	d. Program benefits addressed the <u>key</u> benefits to participating in the program for your company
3.7	e. Was useful in helping to make decision to participate
3.3	f. Motivated your company to participate
3.4	g. Clearly explained how to enroll
3.5	h. Written for the correct decision maker in your company

Sign-up and enrollment Process:

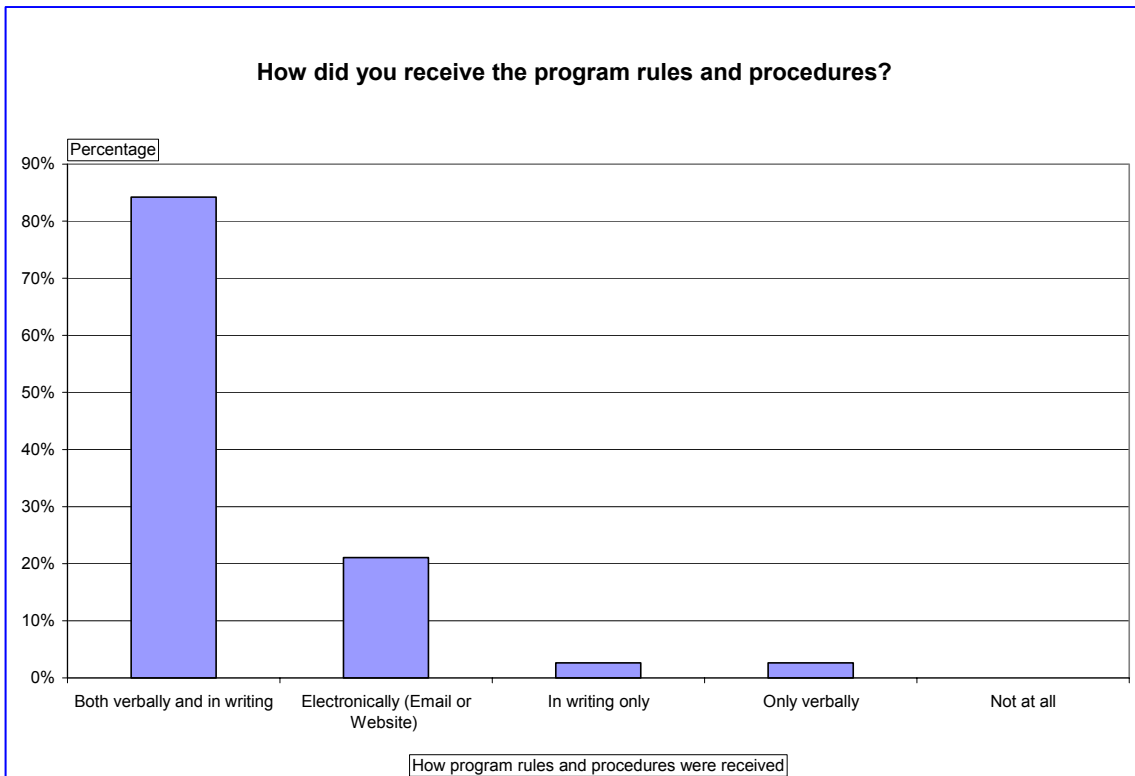
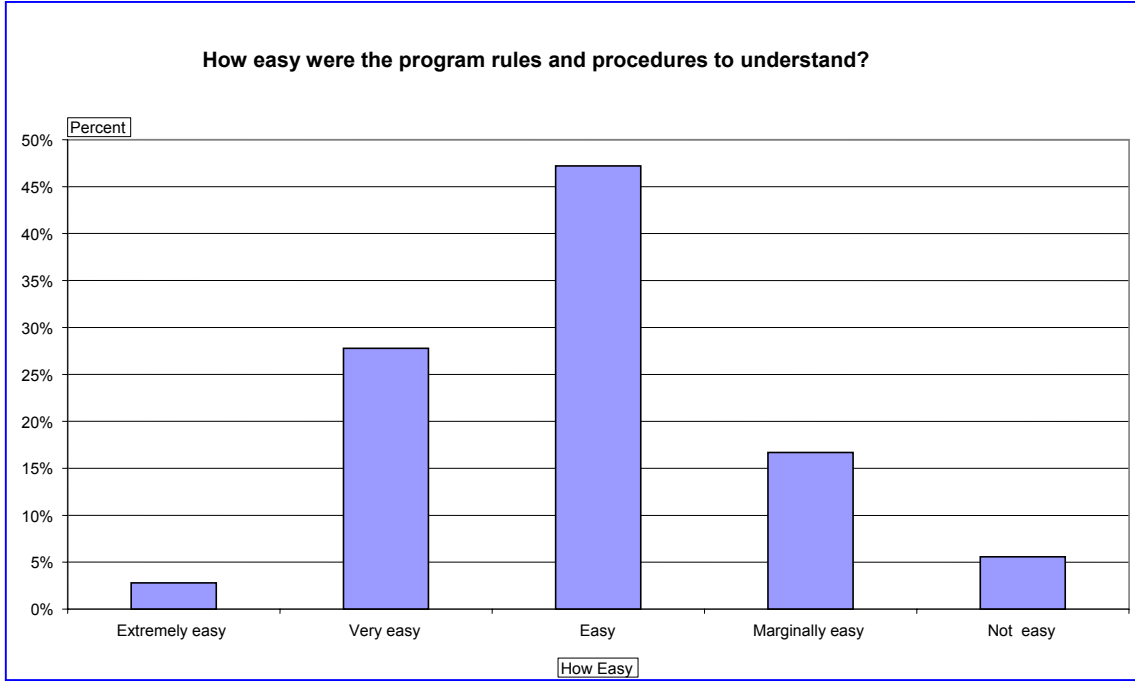
Respondents said the sign-up/enrollment process was straightforward (87%) and almost all (92%) said they received adequate information regarding the process. Overall, 59% rated the sign-up/enrollment process as excellent or good. However, the respondents’

rating of the support they received from their local utility was split, with 48% stating they were either marginally or not satisfied.

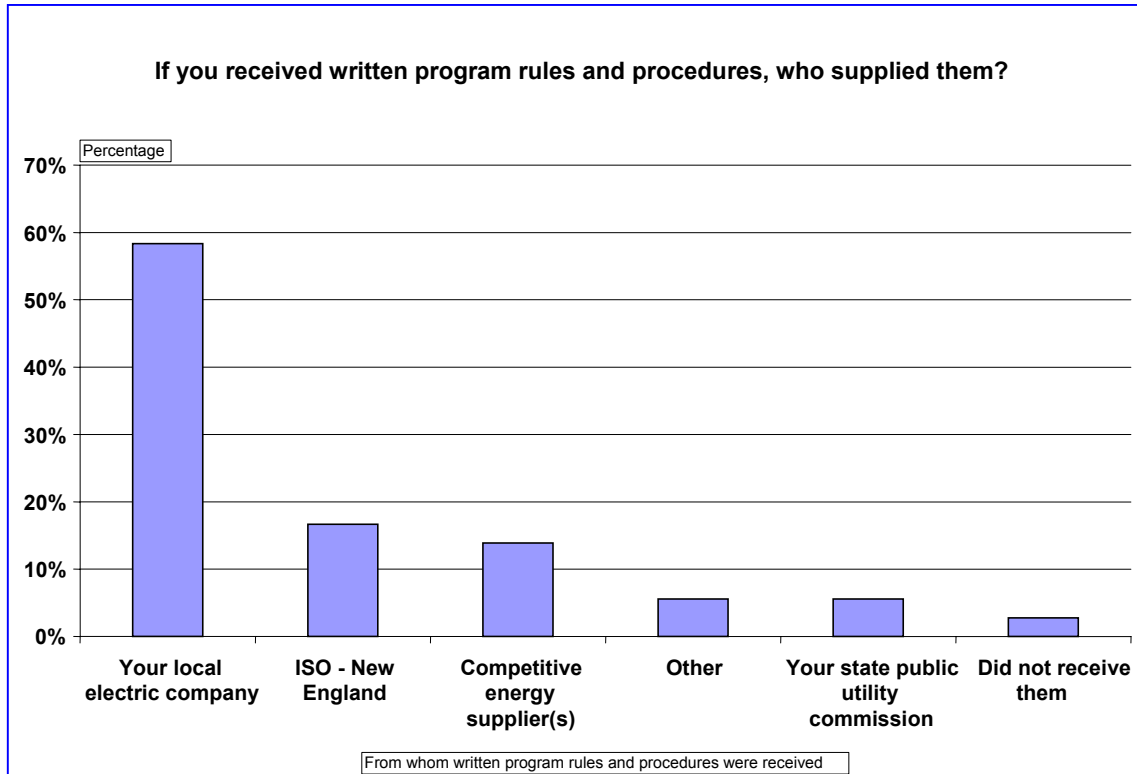


Program Operation:

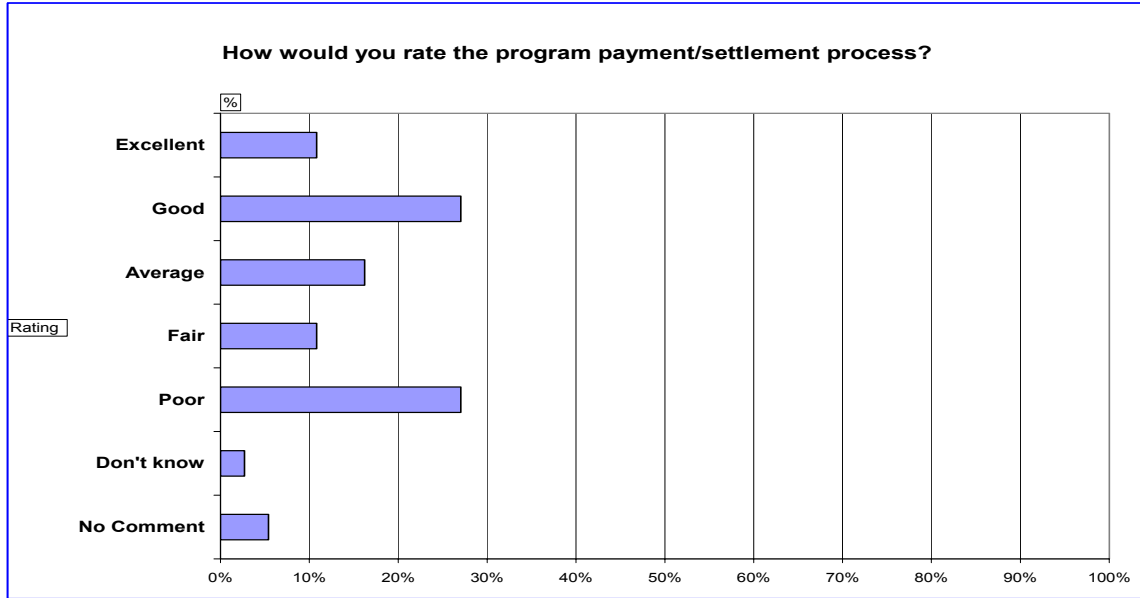
In general, respondents found that the program operation was not overly complicated and that the rules and procedures make sense. 84% received the rules both in writing and verbally.



For the most part program rules were received from three entities, the local utility (58%), ISO- NE (17%) and from a competitive energy supplier (14%).



Respondents were split, however, regarding the settlement process with 38% rating the settlement process as fair or poor and 38% rating the process as excellent or good. Class 1 rated the process somewhat higher than Class 2 respondents.

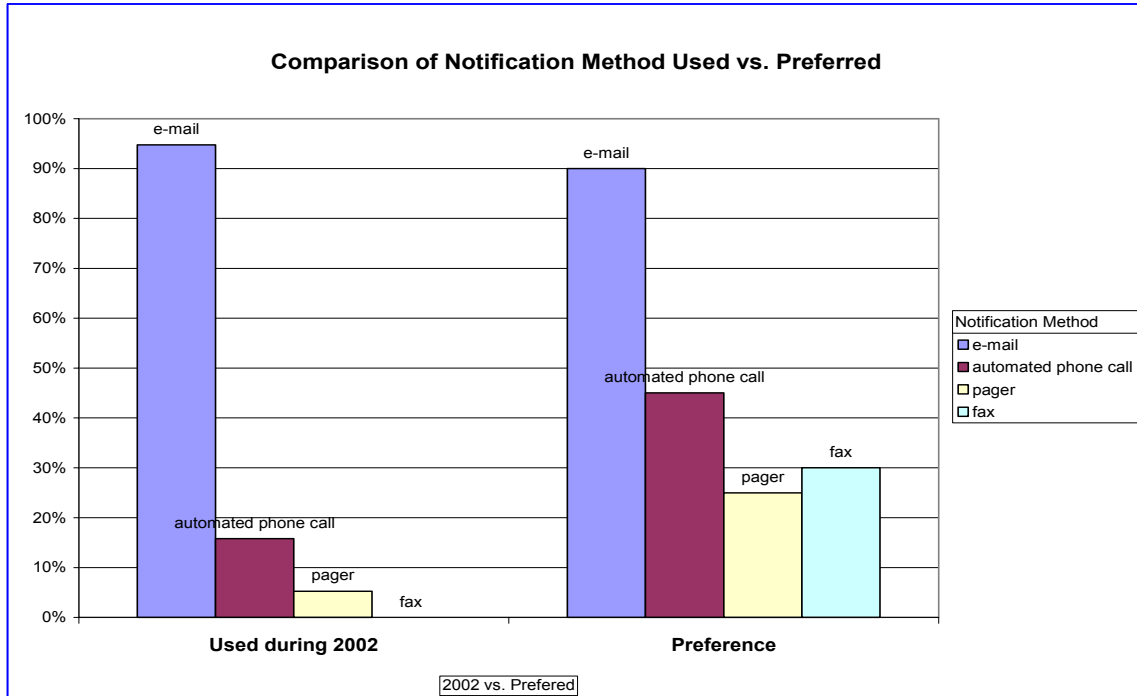


Overall the respondents felt the process was very or somewhat customer friendly. Class 1 customers were very happy with their local utility’s responsiveness to their inquiries, with 70% responding extremely or very helpful.

Curtailed – Price Response Program (Class 2 only):

This section of the survey addressed participant satisfaction with events called for the Class 2 program, and therefore was limited to Class 2 participants. Approximately 66% (25) of the survey respondents were Class 2 participants.

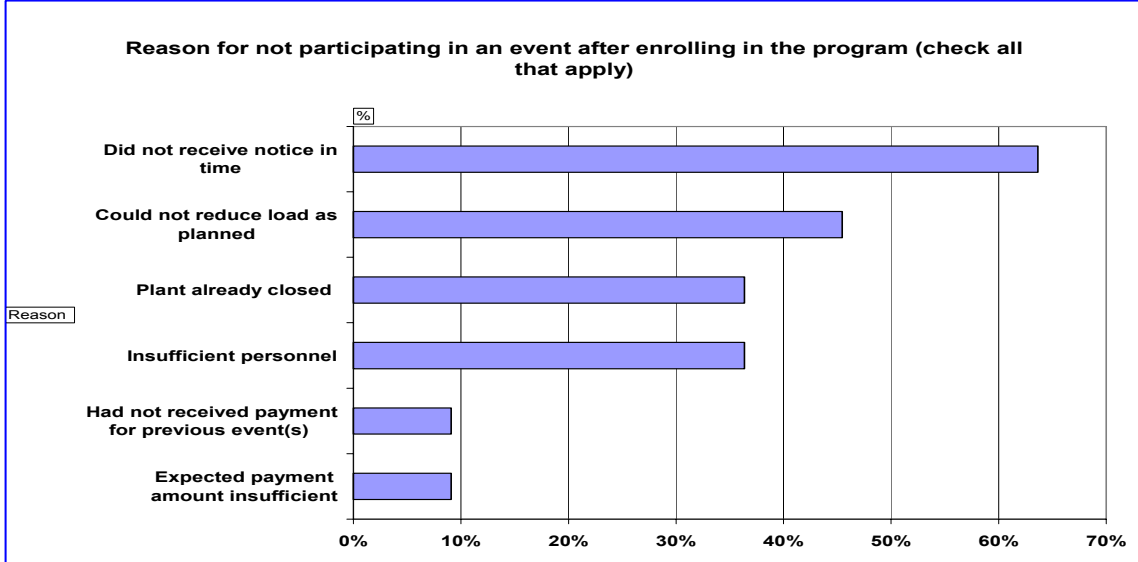
Of the Class 2 respondents, 70% stated that the notification period was sufficient for their company to respond to an event. However, 20% said it was not. Almost all (95%) said they received notification of an event by e-mail, and 16% said they received an automated phone call. When asked which notification method they preferred, e-mail was still the preferred method; however, 45% said they would prefer an automated phone call. Almost a third, (30%) prefer fax, and 25% prefer pager. Sixty five percent would like multiple notifications per employee.



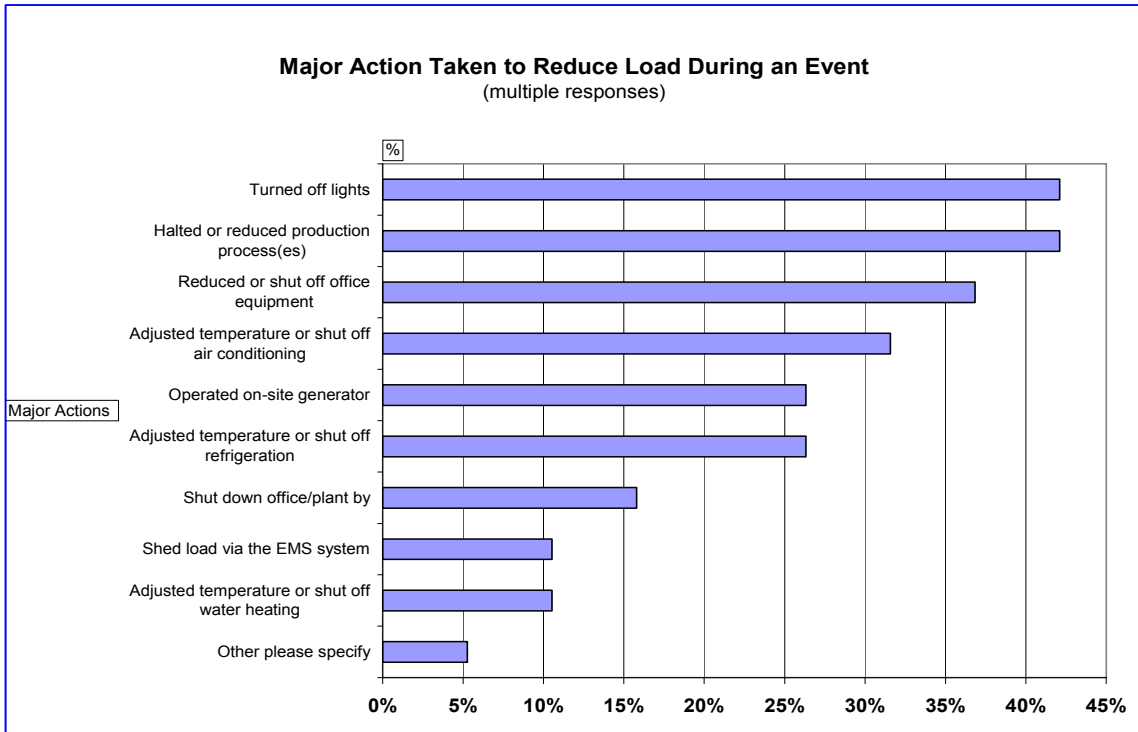
When asked if they believed they received notification for all of the events only 50% of Class 2 respondents said yes. Most rated the message itself as adequate, with one respondent suggesting that price information should be included in the message itself.

The majority (60%) of the Class 2 respondents did not monitor the price forecast during an event. TV and radio were not a factor in deciding to participate in an event. The majority (89%) of respondents participated in less than seven events.

Of the Class 2 respondents that did not participate in one or more events after enrolling in the program (n=11), 64% stated they did not receive notice in time, followed by 45% who could not reduce load as planned.

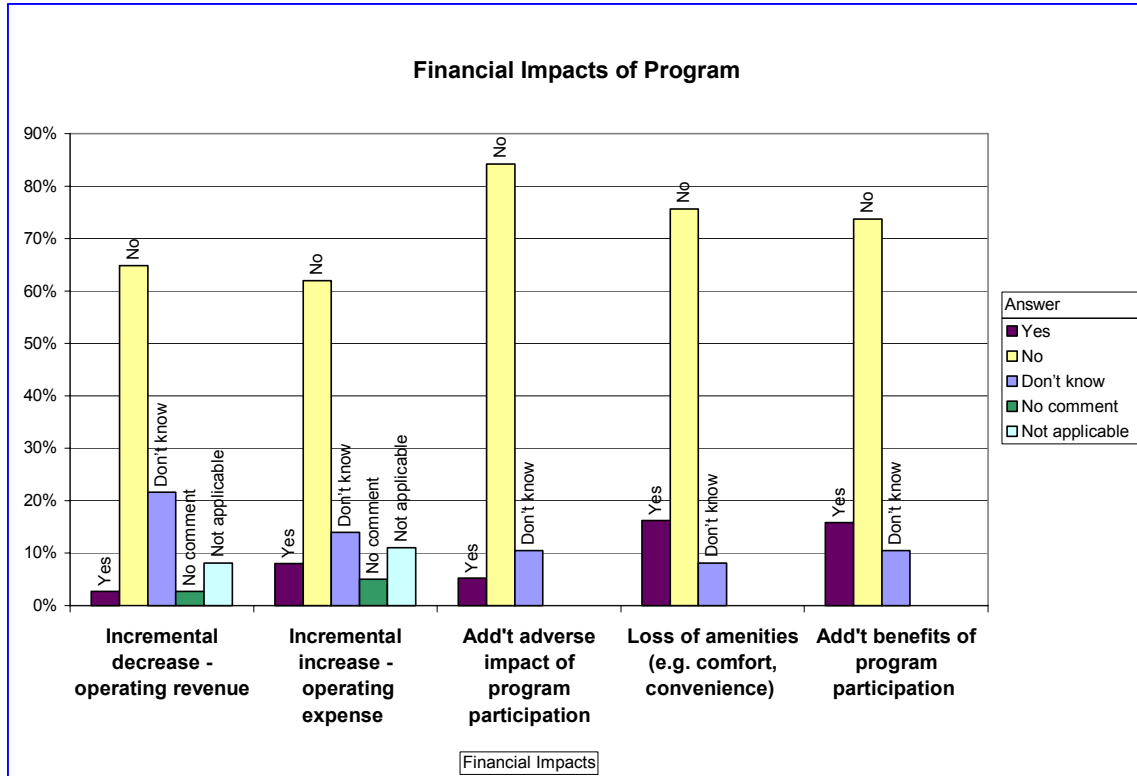


A number of activities were used to reduce load during an event. Class 2 respondents were more likely to turn off lights (44%) and halt or reduce production processes (44%) than they were to shut down the office or plant (17%) or shed load via an EMS system (11%). One respondent scheduled a maintenance outage during a period typically characterized by warm weather.



Financial/Operational:

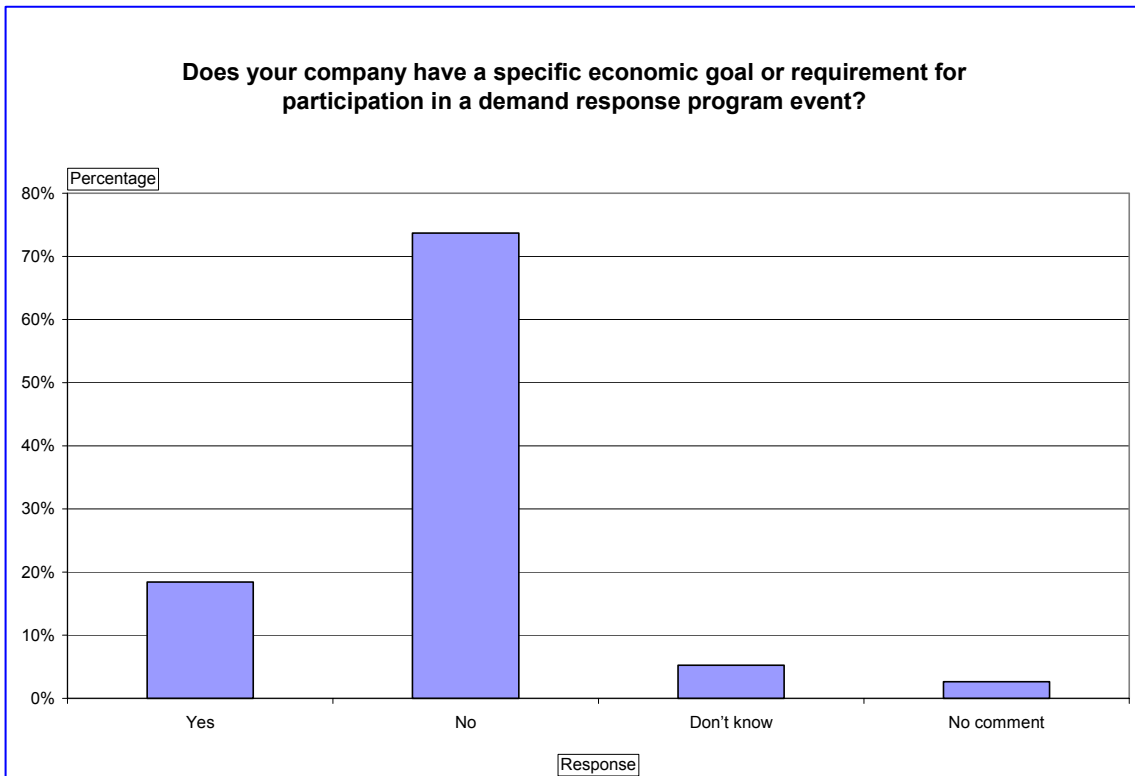
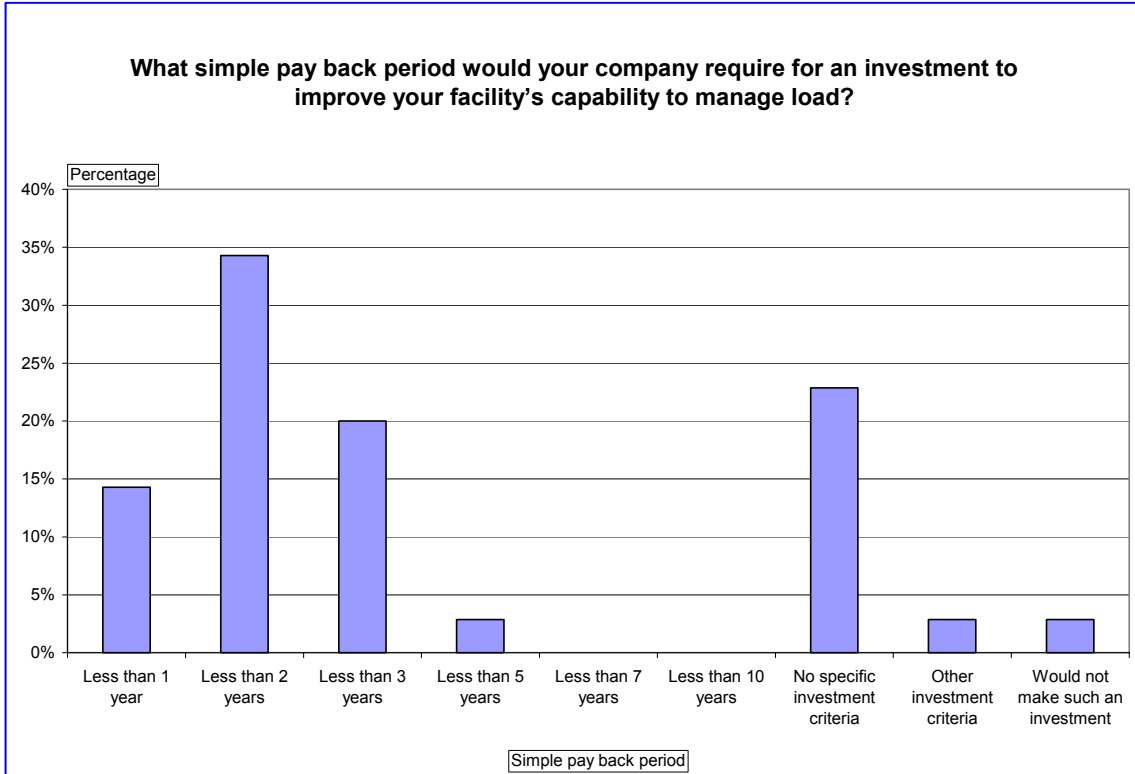
The survey asked a number of questions to ascertain any financial and/or operational impact of the program. The majority of respondents (62%) said there was no incremental increase in operating expense or any incremental decrease in operating revenue (65%) resulting from load interruption or the availability for interruption. When asked if they experienced any loss of amenities, over three fourths (76%) said they did not. For those that experienced a loss of amenities (16%), they ranked the loss as minimal giving it an average of 2.4 - with 5 being an extremely high loss.



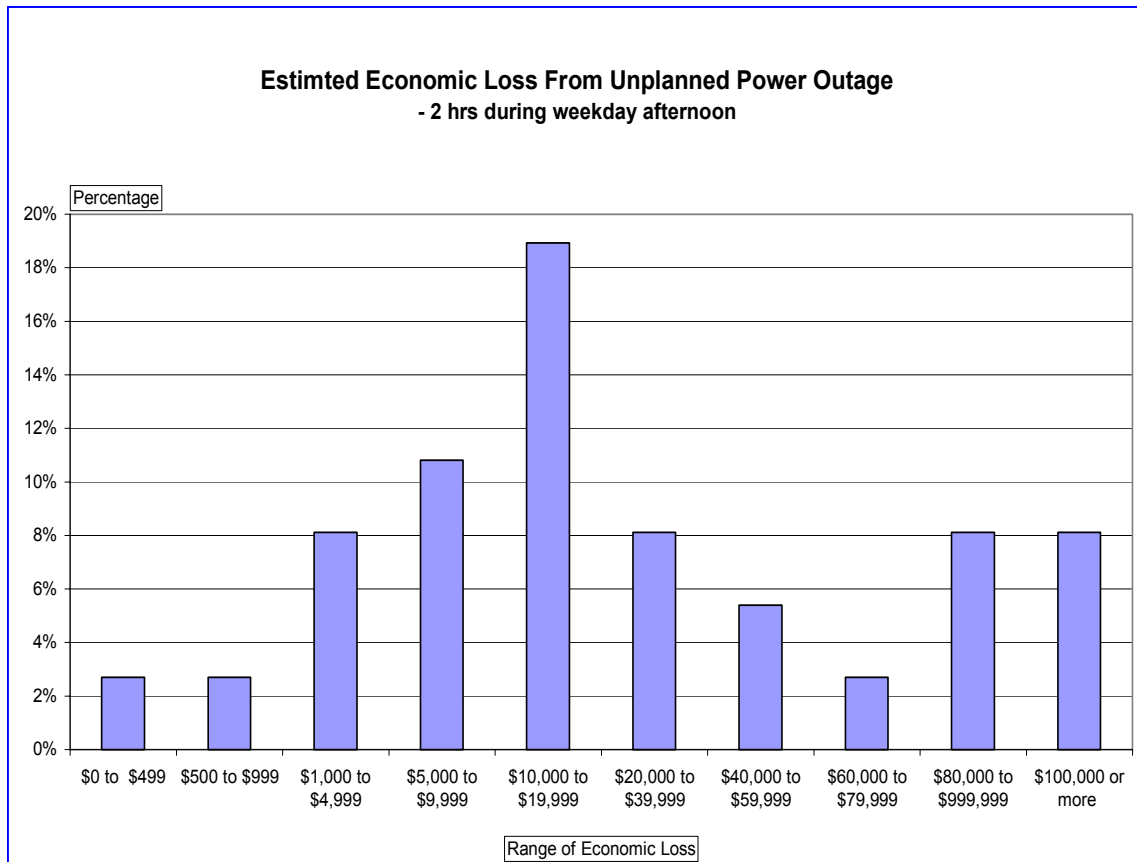
Interestingly, 16% noted benefits in addition to the program incentive payments. These benefits included:

- Emergency preparedness,
- Electrical usage real-time data from RETX (ISO New England’s IBCS vendor),
- Public relations,
- Community participation,
- Development of measurement techniques, and,
- A heightened awareness of the importance of energy conservation in general.

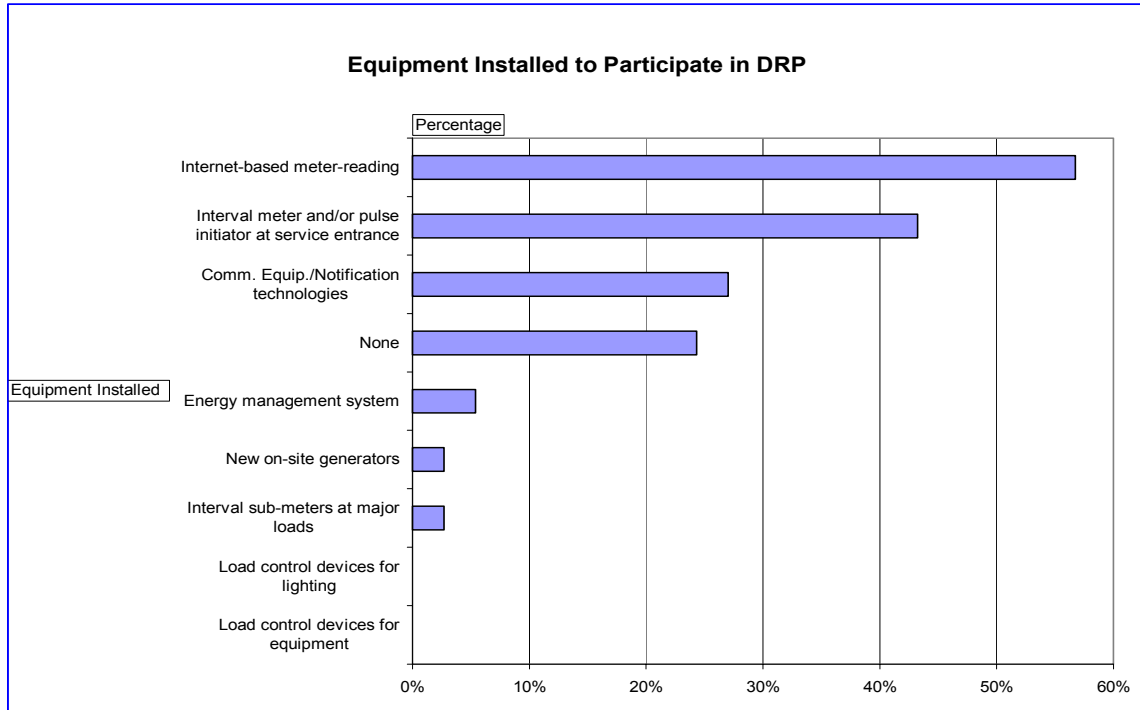
Responses regarding simple payback periods are consistent to what has been found with conservation initiatives of 3 years or less. Almost three fourths (74%) do not have an economic goal or requirement for participation in a DRP.



When asked to estimate the economic impact they would experience from an unplanned power outage for two hours in the afternoon on a weekday, responses ranged from less than \$500 to over \$100,000, with 30% responding in the range of \$5,000 to \$19,999. Those who responded greater than \$100,000 indicated the nature of the loss would be in the loss of salaries, and loss of production, loss of data center operations, and bad press.

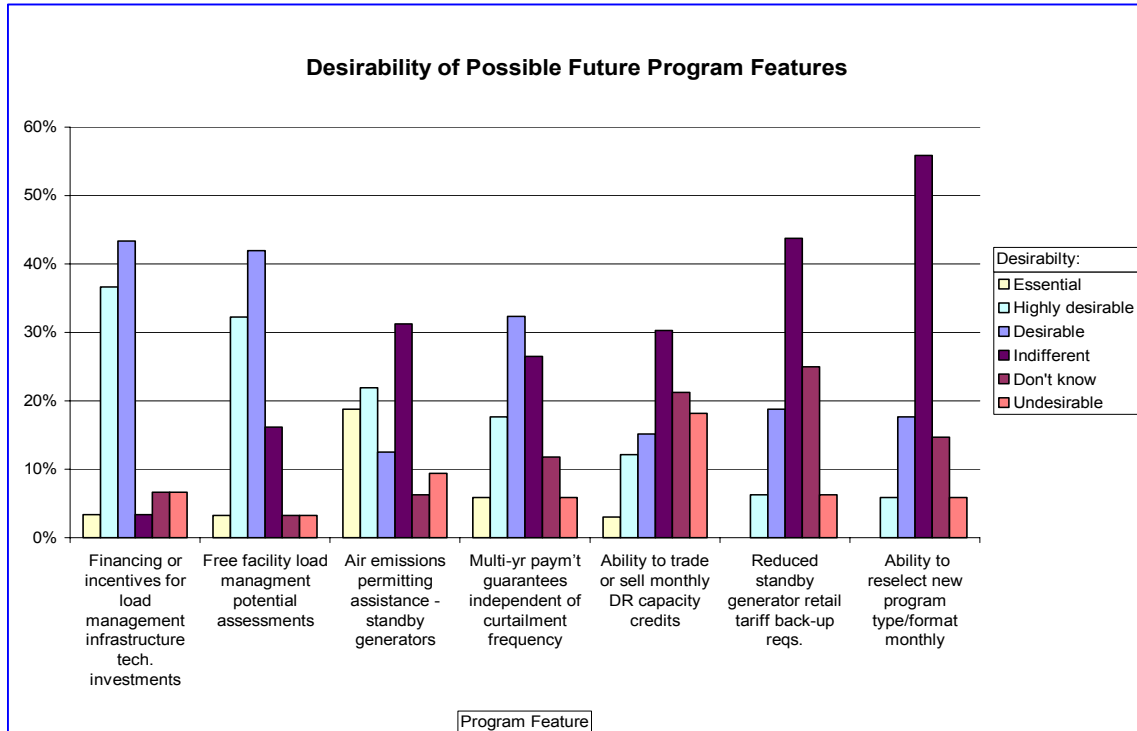


Approximately three fourths of the respondents installed equipment specifically to participate in the program - 57% installed internet-based meter-reading equipment, 43% installed an interval meter and/or pulse initiator at the service entrance and 27% installed communications equipment/notification technologies. For 73% of the respondents, the cost of this equipment was either fully or partially subsidized by a third party (63% by local electric company). The incremental cost for the equipment and its installation ranged from \$0 to \$5,000, with an average of \$2,200.

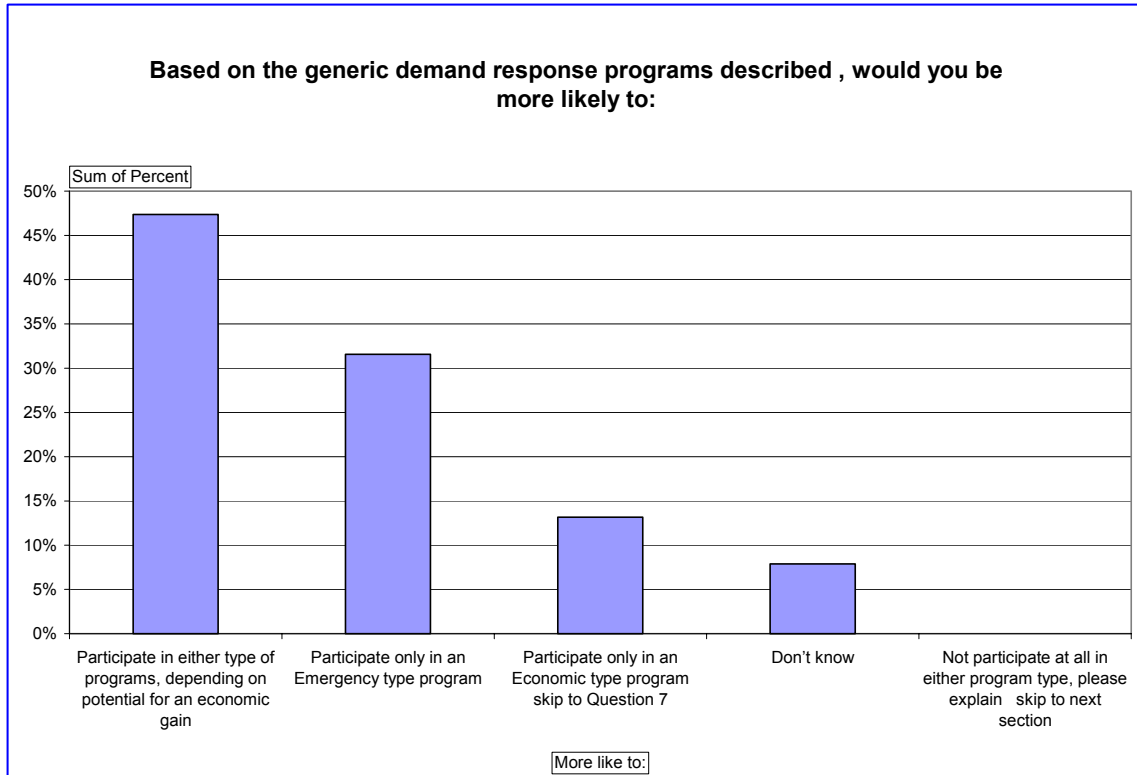


Future Programs:

Respondents were asked to rate a series of potential program enhancements. They ranked air emissions permitting assistance as essential or highly desirable (41%). The provision of financing or incentives for load management infrastructure (40%) and free facility load management potential assessments (35%) ranked high as well. Respondents did not desire the ability to reselect a new program type or format on a monthly basis, or the ability to trade or sell monthly DR capacity credits.



The majority – 84% - is planning to enroll in the 2003 program. Almost half (47%) of respondents stated they would like to be able to participate in either type of program. 63% of respondents would prefer to be called on to reduce load when the real time energy market price hits a pre-established level set for the program by ISO. The majority of respondents are not willing to accept penalty provisions.

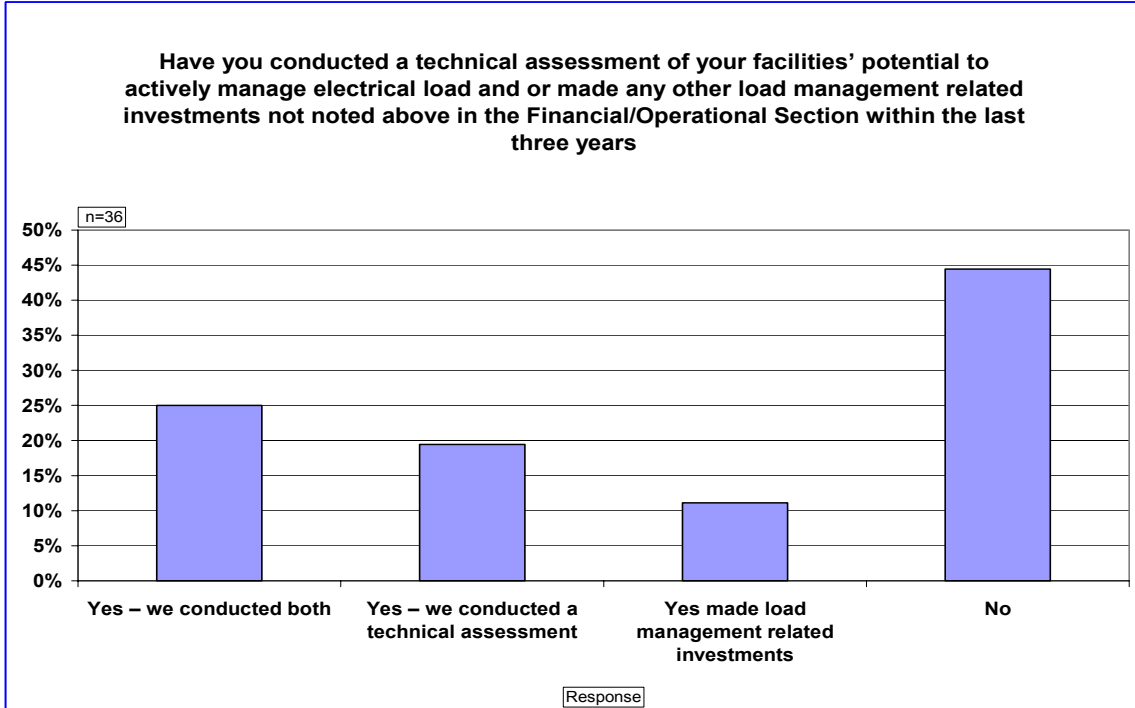


The study found the best time of day to notify participants of an event is 6-8 a.m. (66%) - with another 24% responding 9-10 a.m.

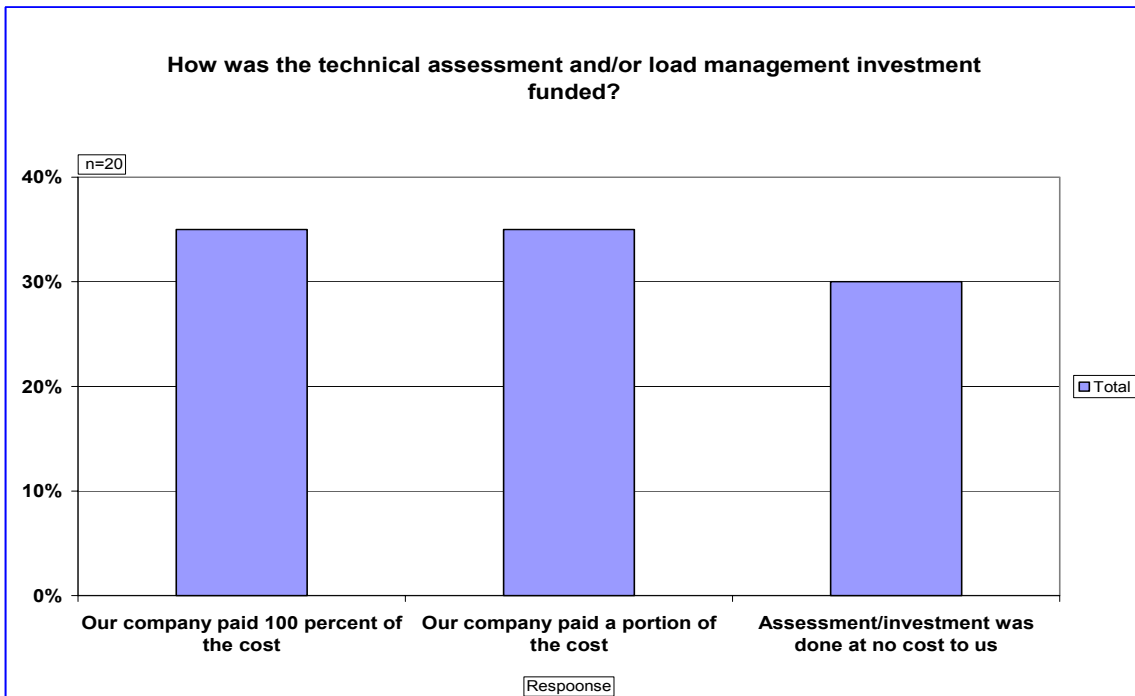
Business Characteristics:

Almost 60% of the respondents were manufacturers. The majority owned their own space (89%). Approximately 60% were at least 7 day multiple shift operations. Less than half had Energy Management systems or process controls in place prior to the program. Respondents estimated that electricity costs comprised on average 11% of their total annual operating or production expense. 72% use gas in their buildings.

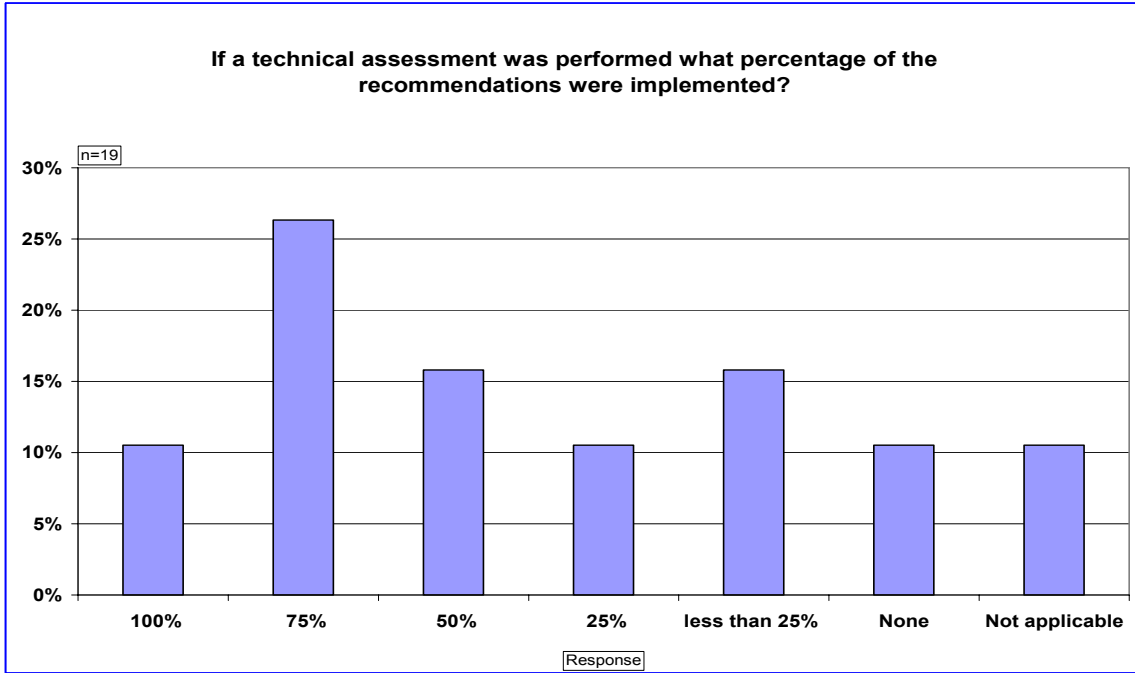
Respondents were asked a series of questions relating to Conservation and Load Management and technical assessments. 43% responded they had participated in a utility Conservation and Load Management Program, while almost half (49%) have not. participated in a utility offered conservation and load management program. Fifty four percent have conducted a technical assessment of their facilities potential to actively manage electrical load and or made other load management related investments.



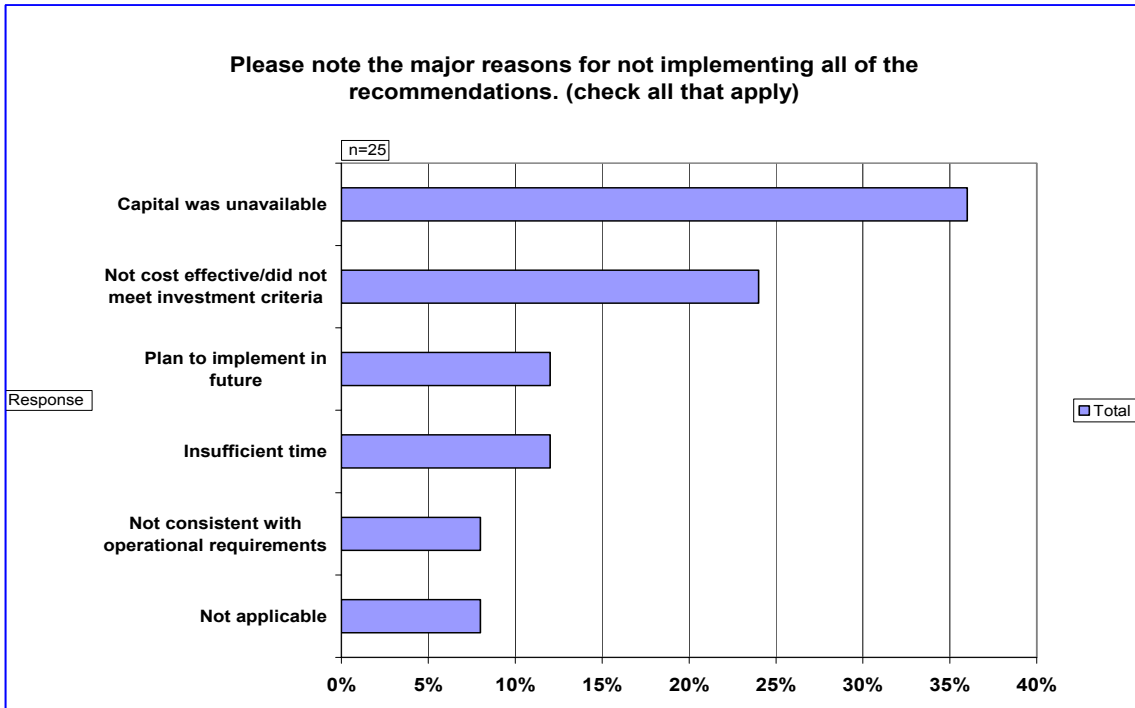
Of the survey respondents that conducted these technical assessments (n=20), 65% received funding for the assessment for all or some of the costs from another source. Of these, 69% reported receiving funding from their local electric utility.



Of note, most of the respondents who had an assessment done implemented some or all of the recommendations, although, only 11% implemented all of the recommendations.



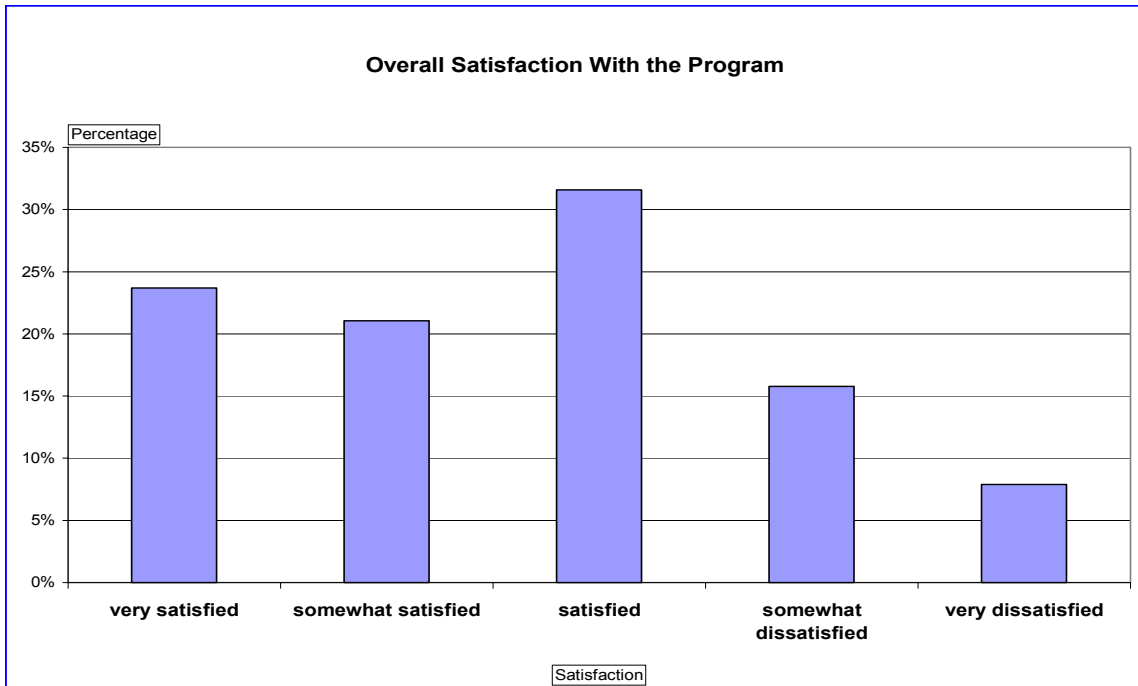
When asked why all of the recommendations from the technical assessment were not implemented the main reasons given were that capital was unavailable (36%) and the recommendation was not cost effective (24%).

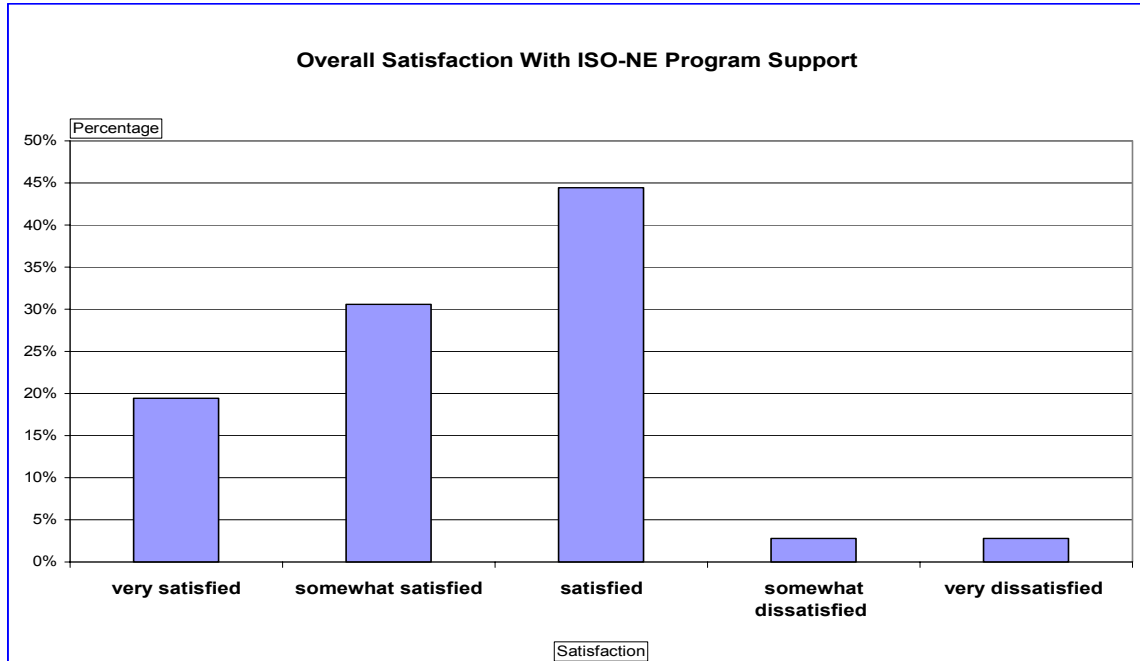


General Satisfaction:

24% of respondents were somewhat or very dissatisfied with the program in general, although, the majority (94%) were satisfied with ISO – NE’s Program support. Respondents stated their dissatisfaction was due to:

- Pricing too low to obtain significant gain,
- Payments very small for their effort, and
- At least four survey respondents stated they had not received payments yet.





On a light note, respondents clearly preferred a Home Depot gift certificate (88%) to a Staples gift certificate.

General Comments by Survey Participants:

Respondents were provided the opportunity to provide comments at the end of the survey. Some of these comments included:

- I missed most of the summer of 2002 because the process to sign up and install took too long.
- Although New Energy's responses to questions were timely, the installation of metering equipment did not occur until October.
- We had to curtail our participation because of CTDEP NOX RACT requirements. It would have been beneficial for ISO-NE and us if the distributed generation permits allowed our company to operate for the LOAD DEMAND PROGRAM (LDP) without forfeiting emergency status for emergency operation outside the limited daily hours for LDP. We could have tripled our curtailment level amount. Our company has the ability to provide emergency response outside of the Southwestern Portion of CT where the program was directed.
- We found the program paid very little compared to the amount estimated from the demand curves.

- Would like to see a better way to communicate times for load curtailment, the earlier the better.
- Program needs financial incentives to really get our attention. We formally had a payment of \$28,000 per year, which was paid to us by our utility for future interruptions. That was eliminated. We were not very happy about that. This program was supposed to make up for the loss of that program. As of this date, we have not seen any real \$\$\$ incentives.
- We are very disappointed with the amount of money we received for our efforts last summer. As good corporate citizens, we have always participated in reducing load when it helped New England or our local area. We will continue to do that, however, we were led to believe that participation would yield a significant financial return. We invested several thousand dollars in installing the RETX meters but have only received a few hundred dollars to date. It took months to even receive the few hundred dollars we did get back.
- This organization enrolled in ISO-NE's Class 2 Price Response Program in early summer 2002. Our intent with regard to our participation was to posture ourselves to optionally take advantage of the program benefits under two scenarios. The first scenario was that in light of a declared event and with a high degree of confidence in maximum energy clearing prices (\$1000/MWh) for a prolonged duration (5-6 hours), we would shed electrical load for compensation. The election to shutdown our process to curtail power would be contingent on the constraints of production schedule and the need to address imminent plant and process maintenance requirements. We did not participate under these circumstances for the following reason. We found that typical energy clearing prices did not remain at elevated levels for predictably long durations. Thus, we could not shutdown with reasonable assurance that load shed compensation would recoup foregone opportunity costs. As well same day" notification did not allow for adequate planning of downtime activities. The second scenario under which we would participate in the price response program was to schedule planned outages during periods of seasonally hot weather. If an event were indeed declared then we would be in position to receive credit for the electrical power that we were not using. We were able to participate on this basis during three events. We intend to enroll in ISO-NE's price response program in 2003. Of particular interest to us is the day-ahead program. We feel that this program will allow us to take advantage of our load-shed capabilities with a much higher degree of certainty regarding compensation. It may also provide an opportunity to better coordinate event days with required plant and process maintenance.
- It is easy to be magnanimous about the '02 program because we were not called on to shut down during the duration of the summer! However, we believe that our participation was helpful to our supplier in that we became part of their safety net and, of course, we realized economic benefit, so the program was mutually satisfying.

- I strongly support the load reduction program and energy management in particular. I would like to investigate energy management from a shaving the peak demand perspective. My only real complaint with the load-shedding program is that we have not been paid for the times that we went off the power grid.
- We recommend ISO New England include some meaningful fixed payment (conditioned on curtailment availability) to participants in at least the emergency program simply for being willing to participate. That way, participants can be compensated for their time and efforts even if New England experiences a cool summer and no curtailments are required. Simply getting ready for a curtailment event involves the commitment of significant resources (time and money.) As described earlier, the ICAP credit alone cannot provide this incentive. [If ISO New England were to institute a locational ICAP market with a price cap no less than several times the cost of a new peaking unit in a location, then the ICAP credit might be sufficient in transmission congested areas, but it would not be enough for the balance of the region.]
- I understand this was the first year and should be smoother next year. Interested in lowering electric bills. Need to follow-up on compensation. Would participate in future shedding.

STAKEHOLDER SURVEYS

Stakeholder surveys were conducted to solicit stakeholder feedback on their perception of the ISO's 2002 Demand Response Program (DRP) and the issues that may affect the future development of DR resources in New England. The following groups were surveyed:

- State Public Utility Commissions,
- Distribution company staff engaged in DRP marketing and operational support,
- Competitive providers of DR related services, and
- Other interested parties, energy policy advocates, trade associations, etc.

The surveys were conducted using a variety of methods. Personal interviews were conducted with the staff of five New England Public Utility Commissions. A focus group session was held with distribution companies. Distribution companies were also asked to submit comments to written surveys. E-mail surveys were sent to competitive service providers and other interested parties. Unfortunately, due to the low response rate of the e-mail surveys, the data collected was insufficient to draw any conclusions.

PUBLIC UTILITY COMMISSION SURVEY RESULTS

What is the priority of power supply issues in relation to other commission issues?

Whereas some states considered DRP to be a low priority, all five of the Public Utility Commissions indicated priority of power supply issues to be high. As expected, some states were very concerned about the future level of congestion costs and the potential for power disruptions.

Public Utility Commission comments reflected different perspectives based on their experience with retail deregulation. Some states have seen a fair number of their large customers selecting lower priced suppliers. As a result, they expect those customers to exhibit demand elasticity should prices increase, i.e., the market should produce DR resources if needed. Meanwhile, other states have not experienced any significant loss to competitive suppliers and therefore may not be confident that market forces will produce DR resources to the needed or desired levels. For example, Vermont still has a fully integrated utility structure in place.

What was the perceived success of ISO New England's 2002 DRP?

Most of the Public Utility Commissions surveyed did not view the program as a success for the following reasons:

- There were an insufficient number of customers enrolled in the program.
- There were numerous start-up problems: The program was rolled out too late, there were customer notification problems and settlement issues, and there was insufficient testing before the program went operational.
- The program was too complex.
- Incentive payments were too small and inflexible.
- Customer education about the need for the program and understanding program requirements was insufficient.
- Class 1 was not called so there is no data on its usefulness as a resource.

What were the perceived goals of the 2002 DRP?

Most Public Utility Commissions felt the goals of the program were to improve reliability, mitigate market power, and protect the environment. Some staff members felt the goals were not explicitly stated or were too vague.

Suggested Future Goals:

Public Utility Commissions suggested the following for future goals:

- Improve load factor and reduce the need for peaking capacity.
- Allow markets to bid on load.

- Achieve regional DR resource parity within a least-cost planning framework.
- Develop non-threatening messages concerning reliability issues.

Who is responsible for ensuring reliability within the Standard Market Design reliability zones?

All of the Public Utility Commissions felt ISO and Response Team Organization were responsible for ensuring reliability within the standard market zones. They also felt state Public Utility Commissions would not become directly involved unless there were problems of a significant nature specific to their state. Some states expressed the desire for a process that would give them a greater role in making decisions on matters directly effecting resource adequacy and/or end-user issues within their state.

Which type of DRP is more important, emergency or economic?

Most of the Public Utility Commissions felt both types of programs were needed, with reliability being the most important. Some felt that DRP designed to meet reliability needs should have mandatory performance requirements equal to that of a generator. They also felt responses to economic focused programs should be voluntary.

How satisfied were you with the load serving entities (LSE or distribution companies) ability and efforts in marketing and communicating DRP to customers?

Responses ranged from very satisfied to stating distribution companies should not be relied on to market the program. Some felt the marketing that did take place was focused mainly on large, as opposed to, residential customers. In addition, there was a collective sense that the ISO needed to be more directly involved in marketing to retail customers due to the immaturity of the retail market.

What are the barriers to the deployment of DR on a regional basis?

Responses were very diverse and included the following remarks:

- Customers do not easily understand DR and they are risk averse.
- Costs to customers are not covered by the program.
- There is insufficient technical support for customers.
- Incentive payments are too low.
- The ISO's corporate culture is predominately transmission focus. DR not often addressed meaningfully in ISO planning documents with sufficient specificity, i.e., marketing plans, cost benefit analyses, etc.
- There is insufficient attention given to the development and deployment of DR resources directed at residential and smaller commercial/industrial customers.
- The amount of time and attention required by Public Utility Commissions to address the FERC transmission and Standard Market Design reform processes left insufficient time and resources to engage in resource planning issues such as DR.

What are the barriers to the development of DR within your state?

Comments included:

- Inadequate price (retail) signals. Standard offer and default service rates that mute trends in wholesale price fluctuations and inhibit direct linkages between the energy suppliers and end-users could make DR viable as a supplier cost management strategy.
- There is an absence of customer aggregation. Particularly among residential and smaller commercial and industrial customers that could give those customer access to DR benefits.
- There is a lack of emphasis on the societal impacts of DR and a method of translating those into benefits, etc.

What is your commission's view on the use of energy efficiency funds for DR development?

Only one Public Utility Commission indicated that efficiency funds were being used for DR development. Reasons stated for not favoring this strategy to a more significant degree included:

- Relying on market to provide financial resources.
- Inadequate funding for energy efficiency.
- Would likely increase the allocation of energy efficiency to commercial and industrial customers that is already significant.

What conditions would have to take place for your commission to support retail-pricing reform (supportive to DR development)?

In general, comments were not in favor of supportive retail pricing reforms. Voluntary TOU rates were a possibility as were tariffs for voluntary participation in load shedding programs. Legislative resistance was cited as a barrier. Most felt it would take a major crisis to gain the support required for such reforms as mandatory RTP rates or removal of legislatively mandated caps on Standard Offer prices.

What recommendations do you have on program designs?

Comments were supportive for the programs proposed for 2003 with enhancement to achieve greater parity between supply and demand resources in terms of the payments received and access to market, i.e., demand bidding. More specificity is required in terms of setting goals for DR resources to reflect the sharp rise in supply costs at various load levels.

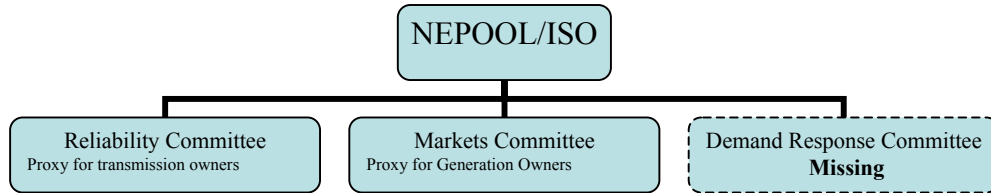
What is the Commission's role in communicating to retail customers the benefits of DR in 2002 and in the future?

There were varying degrees of communication support provided by the Public Utility Commissions on DR deployment and customer enrollment in 2002. Several issued orders to LSEs directing certain supportive actions. In a few instances, letters were sent to customers by a Public Utility Commission or to the LSEs supporting ISO New England's DRP. Some commissions participated directly in informational meetings on DRP hosted by ISO-NE or others. Most saw a limited future role for Public Utility Commissions in communicating the benefits of DRP in their state. Public Utility Commissions rely mainly on orders or decisions as their major form of communication. They cited limited financial and personnel resources as the reason for pursuing a less vigorous role.

Other Comments:

Additional comments offered by Public Utility Commissions at the close of their interview included:

- The concept of resource adequacy, as developed by the FERC, seems to be in conflict with the fundamental premise of the competitive market concept. This complicates policy formulation for DR resource development.
- Although the ISO has increased its commitment to DR by hiring a DR Manager, they are lagging NY and PJM. They need to do a lot more. Their approach has been knee-jerk vs. organized. Regulators would like ISO to propose a regional solution versus allowing each utility to run a different program.
- Few engines/generators make the one MW cutoff for asset recognition. However, if you look at smaller units, say 200 kW each, and utilize the internet to create a dispatchable, virtual utility, distributed generation could potentially provide a greater share of the resource mix.
- The current committee structures for NEPOOL and ISO-NE do not provide sufficient parity in representation of DR interests as compared to transmission and generation ownership interests. In order for DR to become a more viable resource, status and resources should be provided for DR (and ultimate customers) interests to be represented in the ISO's planning and rulemaking processes, which is equivalent to the status currently granted transmission and generation interests, as illustrated in the following organization chart.



LSE (LDC) STAKEHOLDER SURVEY RESULTS

Compared with all other issues your company is addressing, where would you place the power supply issue in terms of priority?

Respondents consistently stated power supply issues were a high priority. Some concerns were expressed regarding the future cost of energy and aging equipment in load centers. One respondent is targeting demand-side management resources to reduce demand on specific load centers of concern.

How successful was the 2002 DRP?

Comments ranged from “fairly successful” to “not very effective.” The more critical respondents cited failure to sign up the desired level of load reductions as an indication of program failure. Other issues mentioned included:

- Low incentive payments to customers.
- Settlement payment problems.
- The low value of ICAP and TMOR credits created through the DRP.
- Problems establishing baseline measurement levels and confusion over customer program activation date.

What were the goals of the program? How do they relate to your objectives?

Some respondents were not clear about the 2002 DRP goals. Others felt the overall goal was to achieve 600 MW of enrolled DR. In some jurisdictions, Public Utility Commissions set goals for LSE DR enrollment to align LSE goals with ISO program goals.

What would you like to see as the main goals of the 2003 program?

Several respondents would like the 2003 program to be more customer friendly and in-tune with customer's needs.

Who do you think should be responsible for ensuring reliability within the Standard Market Design zones?

All respondents felt the ISO has overall responsibility for zonal reliability.

What types of DR are more important to your company, emergency or economic?

Most respondents indicated emergency programs were a higher priority.

What types of marketing and communication initiatives did you participate in or undertake in support of the DRP this year? Do you plan to do anything different next year?

Marketing and communication initiatives reported by respondents included:

- Sent letters to all customers 200 kW or larger.
- Account representatives called on customers.
- Created communication materials for customers explaining what they would need to do in order to participate.
- Held public forums or informational meetings.
- Put program descriptions on web site.

None of the respondents indicated they would do anything different in 2003.

What issues did you face in marketing the program?

Customers were confused about whether to sign up for the Class 1 or Class 2 program. Customers found it difficult to evaluate the potential value of TMOR. Explaining ICAP and TMOR to customers was difficult. Customers seemed to be making only very modest commitments to DRP as a learning step and to gain access to incentives for infrastructure upgrades.

What role does your company see for itself in communicating the importance and benefits of DR to retail customers?

Most respondents viewed themselves as a liaison for the ISO until the market develops further. Some expressed a sense of responsibility to communicate to customers on issues affecting their electric service.

Do you have any comments regarding the ISO'S communication of DRP goals and objectives or future recommendations?

Respondents were divided on whether or not program goals were clearly communicated. Recommendations for the future included:

- Making greater use of the ISO's web site to communicate frequently asked questions (FAQs) and other relevant program information.
- Enhance ISO program support with faster turn around on inquiries and settlement issues. The lack of ISO administrative support in 2002 will likely hurt 2003 program participation.
- Greater consistency is needed in the process used to call an event.

What level of involvement do you believe ISO-NE should have in the design, administration, and marketing of DRP?

Respondents offered the following comments:

- Need to reactivate the DR working group. Last meeting was in May of 2002. The group should have met throughout the summer to resolve and respond to issues.
- ISO needs to listen to comments.
- The DR working group was not consulted on proposed program designs for 2003 or before program plans were brought before the NEPOOL markets committee for approval.
- RETX support was outstanding and helped pull off the program by filling in some program administration gaps.
- The ISO should be involved in program design and administration. The responsibility for marketing the program should be shared between ISO and NEPOOL participants.
- We are concerned about the lack of DRP resources provided by ISO, its program administration ability, and its recommended outsourcing of the administration function.

What was your company's role in the implementation of 2002 DRP and what does your company foresee as its role in the future?

In 2002, LSEs saw themselves engaged in program marketing, signing up customers, installing metering, and paying customers for performance. Few comments were made about future roles. Concern was again expressed about how the 2002 experience may affect 2003 enrollment. It was also noted that distribution companies have more credibility with retail customers than the ISO or competitive providers.

How satisfied do you think customers were with the 2002 program?

Overall, responses were somewhat negative ranging from satisfied/somewhat dissatisfied, to extremely dissatisfied.

What barriers do you see to DR deployment on a regional basis?

Respondents offered the following thoughts and observations:

- States are offering differing DR incentives and support services, and some customers receive service in multiple states.
- Benefits from the DRP should go to the provider and end-users.
- There are different issues (problems) associated with Standard Offer, default service and competitive supply customers.
- Accurate and timely settlements.

What barriers do you see to DR deployment within your service territory?

The only new thought offered, was in regards to concerns about the difficulties of permitting of on-site generation.

What recommendations do you have to improve program design?

Reinstate the DR working group and use the following protocol for communicating and resolving DRP planning, operational, and administrative issues:

- Customer feedback provided to the utilities, or the ISO.
- Processing should be done by the DR working group.
- Recommendations provided to NEPOOL/ISO.
- Recommendations provided by NEPOOL/ISO to FERC.
- Class 1 incentive payments should be made on a \$/kW basis.

Would your company support retail pricing reforms that better align wholesale and retail pricing structures?

Most respondents said they would not support retail-pricing reforms for the following reasons:

- Customers are unwilling or unable to accept wholesale pricing risks due to volatility.
- There is no support for the legislation required to better align wholesale and retail pricing structures.

COMPETITIVE ENERGY SUPPLIERS AND OTHER SPECIAL INTEREST GROUPS

Due to project budget constraints the focus groups planned for these stakeholder groups were canceled in favor of email surveys, which produced insufficient response to draw any inferences about the perceptions of the stakeholder groups. The limited information collected from these surveys was used to reinforce other information developed in the course of the evaluation.

BUSINESS PROCESS INTERVIEWS

Feedback revealed concerns among several stakeholders regarding some facets of Demand Response Program (DRP) administration. Concerns expressed related mainly to ISO New England's inability to respond in a timely manner to questions or queries regarding participant enrollment data, participant activation status, baseline calculations, and settlement calculations. Interviews were conducted with ISO staff and others involved in supporting the 2002 DRP initiative to further illuminate any causal factors related to the concerns expressed.

Operational start up of the 2002 DRP initiative was complicated by the fact FERC approval was not received until late spring, dramatically limiting the time available for training, operations and communications planning before program activation. This situation was further complicated by the unexpected departure of the manager overseeing the start up effort. Initiative staffing was initially reinforced with an individual who also had other full time responsibilities. Indeed, practically all ISO staff supporting the 2002 DRP had other responsibilities of a substantial nature.

In the staffing transition for the Demand Response initiative, a key stakeholder support, planning, and communication network – i.e., the ISO's Demand Response Working Group – was abandoned which eliminated an efficient forum for raising and resolving DRP related issues among key stakeholders supporting program implementation. Due to the ISO's inability to respond in a timely manner to information requests, those seeking information would often initiate multiple inquires to different departments, i.e., customer service, program development staff, etc., creating further inefficiencies through duplication of effort.

A key activity in program enrollment for the 2002 DRP was the processing of NX-11c forms. The NX-11c form includes critical information about the participant such as contact information (personnel names, phone numbers, e-mail addresses, etc.), program Class, the amount of curtailment load contracted, total load at the location, meter number, and physical location. This information is collected by the enrolling entity that forwards it to the ISO. The ISO reviews the information for accuracy and completeness, assigns an asset number (essential for the settlement process), and communicates with the IBCS

contractor to initiate the equipment installation process. The data contained on the NX-11c form is the primary information on program participants and is used to notify participants of events, set up their records in the settlement system, provide primary information to be used in information validity checks, etc.

Interviews with ISO staff revealed that at the outset of the 2002 DRP enrollment, an administrative support person was handling the processing of the NX-11c form on a part time basis. As enrollment activity increased, this person became overburdened. In addition, the short program start up period did not provide ample time to train staff on evaluating and interpreting the NX-11c data. This resulted in some inaccurate or incomplete data on participants being entered into the database.

In an effort to streamline the time required to process NX-11c forms, the ISO initiated a web-based enrollment process in the summer of 2002. Since DRP enrollment was well underway at that time, a situation developed whereby the primary DRP participant data resided independently into two separate databases. It then took additional time to convert all participant data to the web-based solution and review and correct all primary customer information. Having primary participant data residing in two separate databases greatly complicated the process of responding to inquiries and reporting DRP status.

Problems were also encountered with the start-up of the NX-11c web-based enrollment solution due to data format incapability between it and the settlement database. These problems possibility generated additional inquiries for ISO staff from stakeholders attempting to clarify settlement data. Another source of inquiries for ISO staff resulted in differences in settlement baseline calculation formulas between the IBCS which provided participants estimates of the “post event” curtailment savings they had achieved and the base line calculation formulas used by the ISO for settlement. The calculation differences were related to the time period for which the baseline calculations were made, although these differences were minor for the most part, they did require ISO staff time to resolve with participants.

Responding to many of inquiries generated by the data management issues identified above took quite a bit of time (up to months in some cases). This outcome frustrated participants and stakeholders and created doubts (among some stakeholders) regarding ISO’s willingness to commit sufficient staffing resources to support program implementation. The situation was further exacerbated by the lack of formalized protocols at the ISO for handing these issues.

Some operational difficulties with event notification were also a source of participant and stakeholder frustration. Event notices to DRP participants sometimes contained information that was inconsistent with event information posted on the ISO’s web site. In addition, the ISO’s dispatchers may have called a curtailment event but the forecasted data was delayed in being forwarded to the ISO’s web site. This action would then activate a data validation checks within in the IBCS, which would prohibit participants from notifying the ISO of their intention to respond the called event.

Some concerns were also expressed by stakeholders regarding the accuracy of the ISO's hourly ECP forecasts. Sometimes the actual hourly ECP exceeded \$100/MWh but the ECP had not been forecasted to exceed the \$100/MWh threshold required for Class 2 event activation. Therefore, the Class 2 participants could not receive compensation for load curtailment actions. Conversely, sometimes the ECP was forecasted to exceed \$100/MWh but actually never reached that level. In this case, participants would have received the minimum guaranteed payment level of \$100/MWh for load curtailment; however, at that compensation level, participants might receive a much lower compensation amount than estimated by the IBCS, which based estimated payments on the forecasted ECP. This outcome could be frustrating for participants trying to make economic assessments on whether or not to shut plant operations in response to a called Class 2 event.

DISCUSSION OF FINDINGS AND RECOMMENDATIONS

FINDINGS

ISO New England's 2002 DRP initiative exhibited areas of improvement in its efforts to achieve a greater deployment of demand response resources. Those improvements included:

- Increased enrollment of curtailable load (in excess of 180 MW) throughout the region and in particular, Connecticut.
- Greater recognition of geographical differences in economic value of load response resources through the utilization of area specific congestion cost multipliers.
- An increase over 2001 in the amount of load reduction in MWh obtained through called events.
- A fairly successful demonstration of the operational performance of the RETX IBCS.
- 75% of the participants were satisfied with the programs.
- Program participants reported virtually no loss of amenity or any increased operating costs or loss of operating revenues as a result of their participation in the program.

The evaluation of ISO's 2002 DRP initiative has revealed some policy and operational challenges to the further development of DR resources. These challenges impeded the

program's operational and economic success. For instance, 2002 program benefits did not exceed 2002 (first year) costs for Class 1 or Class 2 DR programs as measured by the Total Resource Test. The Total Resource Test is the economic framework utilized by many retail regulatory jurisdictions, especially in New England, to determine extent to which ratepayer resources are being efficiently allocated and to address resource requirements within their respective jurisdictions.

Findings Regarding Impediments to Demand Response Program Cost Effectiveness

Perhaps the most significant impediment to the cost effectiveness of DR initiatives is the cost of incentives paid to end-users for their load curtailment actions. This situation increases the Demand Response resource cost significantly and is inconsistent with the model used in New England to promote energy efficiency investments. Energy efficiency program end-user participants are typically paid subsidies only incrementally to the degree that those incentive payments in combination with the monetary savings gained through reduced energy use allow them to achieve their investment payback criteria. The energy efficiency incentives typically paid to induce customer behavior are proportionately smaller in relation to the total benefits received by end-users, than the proportion incentive payments paid to end-users for DR actions in relation to the total benefits received by them. This outcome results mainly because in the case of energy efficiency resource acquisition the retail market more directly flows benefits back to end-users for their actions, therefore, there is less of a need for supplemental payments. The deregulation of retail energy sales in New England has resulted in a further decoupling of end-user and supplier interests through standard offer or supplier-of-last-resort contracting practices. In these contractual arrangements, several suppliers will often provide the aggregated requirements of several hundred thousand retail customers making it extremely difficult to account for the benefit flow from a single end-user's curtailment action. Such arrangements serve as barrier to any single supplier of these aggregated retail loads to manage their cost of providing retail energy service by contracting bilaterally with end-users (or their aggregators) to reduce their load obligation in high spot market price cost periods.

Class 1 Impediments

Where congestion management and system reliability problems are present, the economics of DR as a viable resource may be quite sensitive to resource acquisition costs. In 2002, TMOR credits alone were insufficient to economically justify DR as a reliability resource (Class 1). In SWCT the Class 1 program benefits came close to exceeding program costs. The economic justification for a DR reliability program must come from a judgment about the appropriate insurance value of load loss (at the retail level). This is a judgment that individual retail customers cannot, for the most part, make in a collective manner for themselves. The ISO or retail regulators are better positioned to assess (through surveys, etc.) the financial premium retail customers would experience as a result of unplanned outages. A more robust and competitive solicitation process could serve to reduce Class 1 costs in SWCT and improve program cost effectiveness.

Class 2 Impediments

In the current wholesale market framework, suppliers retain most of the financial benefit associated with price responsive retail end-user load curtailment. Suppliers, if they have energy supply freed up through end-user curtailment at high demand periods, can then achieve a higher sales margin for the retail energy not served, on the wholesale energy spot market. Conversely, if a supplier of retail energy is short, i.e., forced to buy energy at the spot market price to cover his retail energy sales obligations, then if an end-user curtails load their load, the retail energy supplier interest then avoids an economic loss. In either case, the supplier receives most of the market benefit from the end-user's curtailment action and in comparison contributes little to improving the economics of the curtailment action for end-users.

Price response (Class 2) programs have the potential to be cost effective if they can be deployed to better offset LMP by increasing the coincidence of the maximum curtailment impact with the periodicity of the highest ECP. Data developed through the evaluation indicate only 9% of the enrolled load contributed to reducing system load during Class 2 called event hours. Furthermore, additional economic benefits could be obtained by lowering the \$/MWh trigger for calling a Class 2 event. This would significantly increase the number of hours of economically justified operation. Additionally, a review of the participant survey data indicated, and the analysis of the Class 2 event results confirmed, that even larger manufacturing participants do not monitor hourly wholesale market electricity prices. Some stakeholders reported that even when participants attempted to do so, variances between forecasted and actual ECP values would frustrate their attempts to evaluate the economics of load curtailment verses plant operation.

From a participant's perspective, the economics associated with curtailing load are further complicated by legislatively imposed price caps for retail standard offer or provider of last resort service. These price caps limit the retail cost savings of curtailment actions. Analysis of the wholesale market bidding data for Class 2 called event days July 3, 2002 and August 14, 2002 indicates that the presence of 200 MW of Class 2 load resource could reduce the regional ECP levels at peak times by 8-12%. However, the presence of ECP price caps on August 14 at \$1000/MWh seemed to reduce the impact LRP could have on regional ECP.

Findings Regarding Program Administration Issues

Program Marketing and End-user Enrollment

The participant survey suggests that opportunities exist to improve program enrollment. For example, survey respondents indicated that most (over 60%) would prefer to receive DRP information directly for the ISO, in relation to only 17 percent who perceived they did DRP information directly from the ISO in 2002. Therefore increased ISO communication directly to end-users could facilitate greater program enrollment.

Additionally, a very high percentage of the survey respondents indicated that they attended a program informational meeting and found it useful.

The major reasons (or drivers) cited by participants in the survey for participation in the 2002 program were ranked as follows:

- # 1 to receive payments for load curtailment actions,
- # 2 avoid black outs, and,
- # 3 a sense of corporate responsibility.

These major end-user drivers and motivators should be important considerations in planning future Demand Response program marketing initiatives.

The enrollment results by state revealed that almost 80% of the enrolled curtailment loads were recruited in Connecticut where the PUC authorized the use of public benefit funds to provide enrollment assistance. This financial assistance included incentives for load management infrastructure investment assistance and supplemental Class 1 payment for reliability enrollment. The participant survey results also indicate that enrollment enablers such as load management technical assessments, financing for load management investments, and licensing support for on-site generation would be helpful in increasing participation. Several PUC staffs felt that environmental permitting of on-site generation was a barrier to further DR deployment. Enrollment enablers are necessary to significantly increase the penetration of DR until market imperfections can be overcome.

Program Start up and Settlement

Operational LRP “growing pains” and the lack of available support resources created significant frustration for some of the distribution companies supporting the Demand Response program -and their customers. During startup, there was confusion among stakeholders with regards to terms used to describe customer activation status. Problems with the customer enrollment process allowed incomplete or inaccurate information to reside in the primary participant database. This resulted in settlement calculation errors. Although not large monetarily speaking, they but did require ISO staff time to resolve. The ISO’s modest level of available resources and the absence of sufficiently developed and well understood business protocols delineating staff responsibilities and the processes for handling inquires, resulted in delays in resolving settlement issues and requests regarding participant activation status. Multiple participant information databases made it difficult to clarify and respond to inquiries and to accurately assess and report on program status, i.e., level of curtailable load signed up, customer activation status, participant contact information, etc.

Level of ISO Administrative Support Provided

The participant's survey, stakeholder surveys and process interviews all suggest that if DR resources are to be successfully expanded without stakeholder satisfaction issues becoming a limiting factor, ISO program administration capabilities will need to be strengthened.

Due to the varying degrees to which retail regulation is evolving across New England, and the different levels of support provided by distribution companies, it may take an inordinate amount of time for market intermediaries to emerge with sufficient knowledge so as to enable program marketing and provide the necessary customer support. More ISO "in-field" support will be required to:

- Enable program marketing through support of participant informational meetings and on-site customer calls.
- Quickly identify and resolve operational issues and inquiries.
- Liaison with local stakeholders, i.e., distribution companies, service providers, state PUC staffs and environmental regulators.

Additionally, if greater DR enrollment is to materialize, the ISO will likely need to enhance "backroom support" functions such as customer service, DRP settlement, and program marketing support. Since program participants are end-users, as opposed to wholesale market providers, a larger facility to handle and respond to customer issues is desirable.

ISO and NEPOOL Process Issues

The future efficacy of DR as a viable resource in New England may be somewhat dependent on the organizational processes utilized by the ISO and NEPOOL to plan, develop, and administer the incorporation of DR into the wholesale market process. As characterized by a PUC staff stakeholder, generation owner interests are well represented on the NEPOOL Markets Committee and transmission interests are well represented on the NEPOOL Reliability Committee. However, those who have or potentially could have significant DR stakeholders interests do not have the standing nor a comparable amount of allocation resources within the current NEPOOL or ISO hierarchy with which to develop and advocate for rules and procedures that would be beneficial to DR resource development. Since the development of DR resources could potentially reduce the opportunity to earn economic returns for generation or transmission owner interests, it is not likely the NEPOOL Committees heavily dominated by those interests will approve policies or operating procedures beneficial to DR resource development. The recent action by the NEPOOL Markets Committee to reject DR proposals developed through the NEDRI process, which were then subsequently overturned by the FERC, is an illustration of the problematic nature of the organizational dynamic. If DR resources are to be

increased significantly, how DR policies and plans get formulated, evaluated, and approved needs to be adequately addressed.

PROGRAM RECOMMENDATIONS

As a result of the evaluation, some recommendations have been developed in the areas of policy, program design, program marketing, and administration. We feel these recommendations could enhance the prospects for additional DR resource development within New England.

Policy Recommendations

Class 1 (or Reliability Programs)

Infrastructure cost of the DRP was a modest \$33/kw. Even so, 2002 program costs exceeded 2002 benefits as measured by the Total Resource Test. Since the value of reliability resources at the zonal level is a common good, it may be impractical to rely on a market determination of the appropriate value of such resources. Any attempt to determine a market value for zonal reliability should be done in a manner to ensure the most robust response attainable by allowing for adequate response time and a large variety in responses and include sufficient time for a thorough evaluation of the various options. The ultimate price paid needs to be evaluated against the local value of lost load to ensure that it is not an overly high cost or alternatively to low.

Class 2 (or Price Response Programs)

Since the market benefits achieved through the Class 2 curtailment actions in 2002 were not utilized to fund end-user incentive payments or improve end-user economic benefits from curtailment actions, program incentive payments were larger than would be needed had market benefits from curtailment actions flowed directly to those who took curtailment actions.

In order for DR to become a cost effective resource, this fundamental market failure must be addressed at both the wholesale and retail levels. When you think about the market participants who are the most likely beneficiaries of curtailment resources, it has to be those entities that are managing the wholesale electricity cost of supplying retail electricity. Those are the entities that can either reduce their economic loss by not having to purchase wholesale electricity at a price higher than the one they are obligated to charge the retail customer or, be in a position to earn a higher a margin buy selling the freed up retail electricity into the wholesale market.

Standard Offer and Supplier of Last Resort Contract Administration

Even in New England states where retail electricity sales are deregulated, the retail market does not currently provide a direct link between retail electricity customers (with

load curtailment flexibility) and wholesale electricity procurers. Several current policies and practices do not allow for a free exchange of DR market benefits between the two groups for the following reasons:

- Most retail customers have access through aggregation to Standard Offer (SO) or Supplier of Last Resort (SOLR) service, at price levels near (or below) nominal wholesale price levels, resulting in few deregulated retail sales of electricity. Many retail customers want electricity price protection, and State legislators and PUCs want them to have that protection. The PUC stakeholder surveys confirmed that, absent some significant market or operational failures, those (retail electricity price) protections would carry on for some time. As a result, some policy work arounds to correct for these market imperfections are probably going to be necessary for DR to more fully develop.
- Many of the contractual arrangements for aggregating SO and SOLR supply do not provide any path for SO or SOLR providers to reduce their supply cost risk through bilateral DR contacts with end-users (or their aggregators). This situation is particularly problematic in situations where the jurisdictionally aggregated SO or SOLR service is divided up among several suppliers with no one-to-one relationship between any supplier and individual end-user.

The following SO or SOLR retail jurisdictional contracting arrangements that could be directed by state PUCs that would better align path of DR benefit flow between energy suppliers of retail service and end-users for price responsive DR:

- Attempts should be made to construct SO or SOLR supply contracts that straightforwardly provide an opportunity to fully realize the economic value of demand response to reduce power supply costs.
- Award only one supply contract to provide SO or SOLR services within a defined geographical area such as a county, town, or group of towns. This would give the retail energy supplier a clearer picture of their supply cost risk, especially in an LMP framework. Such a contracting strategy could also be designed to encourage potential retail SO or SOLR service providers to publish curtailment procurement terms for customers within the award area as part of their bid. Additionally, such a process would recognize any unique cost of service attributes within the award area and result in clearer definition of resource costs within the award area so that better resource investment decisions could be made.
- At a minimum, align each retail customer with one primary SO or SOLR supplier, so that the supplier can directly contract for curtailment services with the retail end-users they serve (or their aggregator) as an electricity supply cost management strategy.

- Retail jurisdictional leadership is needed to address structural modifications to retail tariffs which would provide increased market based incentives to SO, SOLR, and non-SO customers which could enable Demand Response initiatives.

For DR price responsive resources to develop to a greater degree, other temporary measures could be adopted to enable the wholesale market system to provide for greater alignment of curtailment costs and benefits until the deregulated retail market for electricity sales can support significantly more bilateral contracting between retail service providers and end-users. As an example, a policy work around that could enhance DR resource cost effectiveness would be to require retail service providers to make financial contributions to fund any end-user's load curtailment actions that comport to ISO's DRP rules. The financial contribution to be made by the service provider should be a measure of the hour's LMP and the service provider's short run marginal (SRMC) cost. Since there would be some sensitivity with regard to disclosing an individual supplier's SRMC, a fair proxy could be the monthly hourly average LMP for the particular zone. The funds created could be used to offset (or support) the DR incentive payments and or other costs made to curtailment service providers (or end-users).

Program Design Recommendations

The following program enhancements are suggested by the foregoing discussion:

Class 1

- The program's major focus should be on those geographical sub-areas in which system resource constraints are most acute.
- Payments to curtailment service providers or end-users should be limited by a reasonable estimate of the value of lost load. This should probably be an upper limit on the amount paid through a competitive solicitation.
- Every effort should be made to promote broad-based, end-user participation in a competitive solicitation, which minimizes barriers to entry. This should have the effect of reducing program cost and increasing the program net benefit.

Class 2

- End-user incentives should be market-based, that is, funded by bilateral arrangements that give end-users the opportunity to manage their load and retail service providers the opportunity to manage their costs in response to the economic value, i.e., the hourly LMP savings that can be expected from load curtailment.

- DR programs should accordingly be designed to promote innovative retail pricing, including fostering metering and communications infrastructure improvements.
- Greater emphasis needs to be placed end-user education and training. That would help them maximize their economic return by curtailing load when the greatest system benefits can be obtained. End-user education also needs to include technical training regarding load management options and strategies.
- It appears that the cost effectiveness of Class 2 DR can be significantly improved by increasing the hours of program operation by avoiding unnecessary limitations on the scope of price-responsive load management. Flexibility needs to grant to end-users by not overly limiting the hours (or seasons), which the program can operate and by also allowing lower cost hours to qualify as well. The Benefit Cost Analysis indicated that permitting hours of program operation between \$50/MWh and \$100/MWh would substantially improve Class 2 program cost effectiveness.

Program Marketing Recommendations

The participant stakeholder survey provided several suggestions on how program marketing could be improved:

- End-users indicated a strong desire to get more information directly from the ISO in addition to receiving valuable information from distribution companies. Therefore, enrollment could also be improved by if the ISO were to open up additional channels of communications with end-users who indicated a preference for e-mails. The ISO should undertake the development of a participant target list including contact information on key individuals. Periodic program briefing emails, frequently asked questions, as well as special notices should be sent to both enrolled and potentially enrolled end-users and other stakeholders. Some stakeholders who suggested greater use of the ISO's web site to inform participants and other stakeholders on program issues and procedures.
- The participant survey indicated End-users also seemed to get a lot out of informational meetings and a high percentage of the 2002 participants had attended an informational meeting. This would suggest that enrollment could also be enhanced if the ISO facilitated more meetings with end-users. Such meetings could be utilized both for DRP recruitment and to help educate end-users on how to more effectively participate in the DRP initiatives. A couple of alternative meeting formats should be developed for different target audiences, i.e., one for senior executives, another for facility operating managers and engineers, industry specialization could also be useful. An additional benefit of such meetings would

be to provide the ISO with valuable (real time) feedback regarding end-user needs and issues.

- More end-user support enablers such as load management site assessments, financing for load management infrastructure investments, onsite generation licensing support, etc., were identified as beneficial enablers in the participants' survey. This finding is also supported by the much higher DRP enrollment results in Connecticut where some of these support services were approved by the Connecticut DPUC for funding with systems benefit funds. These end-user enablers could be very useful in those zones looking at higher LMP impacts. How these enabler services could be funded is an issue. However, if the operational effectiveness of the DR initiatives could be improved, then perhaps it would be cost effective to fund these enabler services through a zonal or a jurisdictional energy sales adder, especially in zones with higher congestion costs. It may also be in some retail jurisdictions' (within New England) provincial economic interests to fund these enabler services if the total cost of service within the jurisdiction could be lowered through increased DRP participation.
- To the extent possible, increase the lead-time between program announcement and program initiation to allow more time for informational and other processes to gain recognition and to reduce the spiking of the program administrative workload associated with program enrollment.

Program Administration Recommendations

The level of Administrative Resource Support Needed

The results of the stakeholder surveys, the process interviews and the participants' survey all indicate that additional DRP enrollment and growth will require significant increases in ISO's program administration support capacity. Some of these capacity gains can hopefully be accomplished through the maturation of the internet-based enrollment process's accuracy and effectiveness. The new open architecture IBCS through standardization of the baseline calculation methodologies and other enhancements could also improve the ISO's DRP administrative capacity. However, vigilance needs to be exercised to ensure the implementation process is managed in such manner, i.e., adequate preoperational testing, phase in, etc., as to not create new administrative challenges or burdens.

As noted earlier the jurisdictional support resources available to support DRP implementation varied widely across the region in 2003. As a result, several retail jurisdictions report low levels of program enrollment. In response to a question on the distribution company stakeholder survey, no responding entity indicated they planned to do anything different in 2003 than they did in 2002. In fact there could be a regressive trend in Connecticut were the support was the most significant in 2002 because the public

benefits used to fund DRP support are being tapped to address the state's overall general budget fiscal difficulties.

The immaturity of the retail market deregulation (i.e., the lack competitive service providers and bilateral DR contracting, etc.) and the uncertainty and the unevenness regarding the availability of jurisdictional resources support for DRP implementation throughout the region, may necessitate the ISO to strongly consider significantly stepping up its DRP field support resources. If DRP enrollment is to increase, then DRP program people resources are needed to support several field implementation functions:

- Enabling the program marketing and enrollment processes by targeting and coordinating available marketing/enabling resources, cooperatively planning and participating in end-user informational meetings, facilitating and coordinating local stakeholder communications.
- Support the DRP implementation and program operational activities through active monitoring of end-user activation, quick identification and resolution of operational problems or bottlenecks, assist with end-user training, to act as a liaison between end-users and ISO program development and customer service staff.

The appropriate amount of DRP field support may vary across retail jurisdictions, depending on the nature of local support available and the criticality of the DR resource need within particular zones. It would seem logical that for the NEMA/Boston and the Connecticut zones a dedicated resource could be needed for each zone because of the level of resource need. Another resource may be able to cover Vermont, New Hampshire and Maine. At a minimum a least two and perhaps three qualified individuals could effectively be utilized in a field support role by the ISO until the DRP enrollment ramp up has peaked.

The 2002 program year experience strongly suggests that additional customer service support dedicated to handling the DRP initiatives is needed. Feedback from several sources strongly suggests the ISO's Customer Service function was overwhelmed by the level of DRP related support required in 2002. Additional people resources are needed to actively and aggressively monitor the NX-11c data collection process to ensure the information being provided is accurate and complete and any actions or operational decisions that may be required are also handled properly. If there are problems with the primary customer data collected or in ISO customer specific information developed in the enrollment process, then those problems will have a multiplier effect on amount of staff time and effort required to address subsequent end-user activation or settlement issues. And if DRP program enrollment accelerates based on the approval of higher DRP payments levels for 2003, then any problems with the collection and dissemination of end-user data could lead to a serious customer and stakeholder satisfaction problems. Additional customer services resources are also needed to receive and promptly follow-up on field or end-user generated inquiries. When those raising the questions or concerns do not perceive their issues are being addressed in a responsive manner, then (as was the

case in 2002) they begin to go outside the ISO's Customer Service organization to seek assistance. This then creates problems for other ISO functions and creates organizational inefficiencies that only exacerbate the DRP's administration challenges.

Settlement Process Recommendations

Another facet of the ISO's program administration that could benefit from additional attention in 2003 is the DRP settlement process. In 2002, the process of settling the DRP accounts was highly integrated into the overall supplier settlement process and handled in a fairly mechanical manner that was seemingly unable to detect some basic problems with data going into and coming out of the settlement process for DRP accounts. While the resulting problem did not result in significant monetary problems in aggregate, several DRP customers were affected and the resulting problems took a long time to resolve. This created some significant frustration and concern with end-users and other stakeholders. The DRP data going into and coming out of the settlement process needs to be closely reviewed for any irregularities or anomalies. The DRP settlement is both new and somewhat intricate and learning is still ongoing. Therefore, relying completely automated process for DRP settlement without rigorous quality assurance review by trained individuals, risks end-user and stakeholder confidence. If more people resources within the existing settlement function cannot be efficiently allocated to address this issue, then consideration should be given to handling the DRP settlement process in a separate (and perhaps functionally separated) manner until the activity is more mature.

During the evaluation process, several questions and concerns about the ISO's willingness to dedicate sufficient resources to the DRP's administration were raised by PUC staffs, the distribution companies, and even from competitive providers of DR services who are active in other markets but currently not active in the New England market. One stakeholder made a telling comment to the effect that it was "good" that DRP enrollment was not greater in 2002; otherwise, the program administration (i.e., customer service) problems would have been very much worse. Some stakeholders indicated they are cautiously watching the ISO's commitment to effective DRP program administration and weighing to what degree they are willing to support program out of concern about the risks for end-users and their own standing with those end-users. In an environment where resources (both human and capital) are constrained, the commitment of additional administrative resources to a resource development initiative that is still proving its worth and struggling to be cost effective is a difficult management challenge. The ultimate judgment may turn on one's perception regarding the availability of other actionable options, which could mitigate nearer term reliability and market power concerns.

CORRECTIVE ACTIONS ALREADY TAKEN OR INITIATED BY ISO-NE

The ISO, in recognition of the issues that were precipitated in the administration of the 2002 DRP, has taken the following corrective actions to date:

- Increased staffing by adding a full time Demand Response Manager and three full-time program development, analyst, and administration staff.
- Reactivated the Demand Response working group as a clearinghouse for current DRP information and to identify and resolve operational issues.
- Established a more formalized system of business protocols to address:
 - Enrollment/Registration
 - Activation of Assets
 - Utilization of Assets
 - Settlement and Payment
 - Customer Complaints and Disputes
- Prepared specifications and issued development contracts for an open IBCS solution to standardize participant baseline calculations and processing of participant information.

Additional commitment to the follow through on the corrective actions already being implemented should improve the program administrative processes in 2003.

APPENDICES

APPENDIX A - 2002 CLASS 2 LOAD RESPONSE

2002 Class 2 Load Response (MW)												
Hour	26-Jun	3-Jul	23-Jul	30-Jul	31-Jul	5-Aug	13-Aug	14-Aug	15-Aug	19-Aug	10-Sep	16-Sep
8	0.0	0.0	0.0	2.3	0.0	0.0	0.0	16.3	13.2	0.0	3.5	0.0
9	0.0	0.0	0.0	2.9	1.2	4.0	0.0	18.1	14.3	0.0	3.4	0.0
10	0.0	0.0	0.0	3.3	1.7	3.9	0.0	17.7	14.3	0.0	2.6	0.0
11	0.0	0.0	0.0	3.7	1.2	3.9	0.0	14.8	14.2	6.7	1.2	0.0
12	0.0	0.9	0.0	4.0	2.1	3.4	0.0	11.3	14.5	2.4	1.5	0.0
13	0.0	1.3	0.0	3.0	2.3	3.3	0.0	13.7	15.5	3.6	2.8	0.0
14	0.0	1.6	3.9	4.2	3.5	4.2	0.0	10.1	16.0	6.5	3.3	0.0
15	0.0	2.4	4.5	6.1	2.0	4.8	0.0	10.1	16.1	3.2	2.5	0.0
16	1.4	2.2	5.7	6.8	1.5	5.0	1.7	12.2	16.0	2.8	2.3	9.8
17	1.0	2.3	8.9	7.5	2.1	5.4	1.9	12.3	15.5	9.1	2.8	4.9
18	3.0	1.6	10.6	8.6	2.7	4.5	2.0	15.8	15.3	3.6	3.1	4.4
19	4.4	1.6	14.7	9.0	2.0	5.2	2.2	8.9	14.9	1.4	3.4	5.1
20	5.2	1.5	15.1	10.1	2.6	8.6	2.9	9.2	15.4	2.2	3.2	7.5
21	6.2	1.8	17.2	9.5	2.9	4.4	3.1	9.1	16.0	1.8	3.2	6.9
22	7.6	1.6	16.9	9.8	2.9	3.4	3.3	9.3	15.2	1.3	2.7	7.4
23	8.1	1.3	17.3	10.7	3.1	3.8	3.3	8.4	13.9	5.3	2.5	11.6

ATTACHMENT A

PARTICIPANT SURVEY - INSTRUMENT

ISO New England 2002 Demand Response Program Evaluation Participant Survey

Welcome and thank you in advance for participating in the ISO – New England 2002 Demand Response Program (DRP) Evaluation. Your answers to the following questions will be essential in determining future enhancements to the program - enhancements which may improve system reliability and potentially help lower electricity costs.

Our Promise: We at Townsley Consulting Group promise to keep all responses confidential.

Instructions: This survey **covers 9 topics**. Please provide answers to all of the questions to the best of your ability and **fax** your completed survey back to Michael Townsley at **(860) 388-6599**. Because this survey is reaching you later than the e-mail version, we are extending the response due date to 12/06/02 for the gift certificates.

If you have any questions regarding this survey please call Cheryl Mattson at (860)922-8878 (or Michael Townsley at (860)304-2412).

REMEMBER ALL RESPONSES FROM FAXED SURVEYS RECEIVED BY 12/06/02 WILL RECEIVE A \$25 GIFT CERTIFICATE TO EITHER HOME DEPOT OR STAPLES - SO DON'T DELAY!

Program Communications/Marketing

1. How did you first hear about the 2002 program(s)?
 - a. Your local electric company
 - b. Competitive energy supplier(s)
 - c. Other service provider
 - d. ISO New England
 - e. Your state public utility commission
 - f. Trade Association
 - g. Through an information meeting with multiple sponsors
 - h. Newspaper
 - i. Other please specify _____

2. From whom do you prefer to receive information about the program(s)? (*check all that apply*)
- a. Your local electric company
 - b. Competitive energy supplier(s)
 - c. Other service provider
 - d. ISO New England
 - e. Your state public utility commission
 - f. Trade Association
 - g. Through an information meeting with multiple sponsors
 - h. Newspaper
 - i. Other please specify _____
3. How influential were each of the following in your decision to participate?
Please respond with either: **Extremely, Very, Somewhat, Marginally or Not**
- a. Marketing material _____
 - b. General informational material _____
 - c. Local electric company _____
 - d. Competitive energy supplier(s) _____
 - e. ISO New England _____
 - f. State public utility commission _____
 - g. Trade Association _____
 - h. News media _____
 - i. Other – please specify _____
4. Please indicate your three main reasons for participating in the program by placing a 1 next to your first or primary reason, a 2 next to your second reason and a 3 next to your third reason.
- a. Receive payments for load reduction
 - b. Avoid Blackouts
 - c. Response to public appeals
 - d. Lower the price of electricity for everyone
 - e. Corporate Responsibility
 - f. Lower your energy costs
 - g. Other please specify _____
5. Who (title) was the key decision maker regarding participation in this program?
- a. CEO
 - b. CFO
 - c. Division Director
 - d. Plant Manager
 - e. Facilities Manager
 - f. Facilities Supervisor

KEY: Check Box- Click	Drop-down Box – Select	Text Box – Type over black area
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6. Did you attend an informational meeting? If yes indicate how useful was it by circling the bolded response?
- a. Yes I attended a meeting and it was
 - i. Extremely useful
 - ii. Very useful
 - iii. Somewhat useful
 - iv. Marginally useful
 - v. Not useful
 - b. I chose not to attend
 - c. I did not hear about an informational meeting

7. Please rate how desirable each of the following communication methods are for informing you about future demand response program features/enhancements?
Please respond: **Extremely, Very, Somewhat, Marginally or Not.**

Communication method	Desirability
a. Brochures	_____
b. Newsletters	_____
c. E-mails	_____
d. In person contact from an account rep	_____
e. Bill stuffers	_____
f. Letter	_____
g. Web sites	_____
h. General Informational Meetings	_____
i. Technical Informational Meetings	_____
j. Radio	_____
k. TV	_____
l. <input type="checkbox"/> Other – please specify _____	_____

8. Please indicate if you received any marketing material (e.g. **Brochure, Newsletter, Flyer, Letter, Program fact sheet, Combination of above, or Full marketing package**) from the entities below, note the type(s) received and provide an overall rating of the material (**Excellent, Good, Average, Fair or Poor**):

	Entity	Materials	Rating
a.	<input type="checkbox"/> Local electric company	_____	_____
b.	<input type="checkbox"/> Competitive energy supplier(s)	_____	_____
c.	<input type="checkbox"/> Other service provider	_____	_____
d.	<input type="checkbox"/> ISO New England	_____	_____
e.	<input type="checkbox"/> Public utility commission	_____	_____
f.	<input type="checkbox"/> Other - please specify below: other entity: _____	_____	_____
g.	<input type="checkbox"/> No marketing materials were received skip to the next section		
h.	<input type="checkbox"/> Don't know skip to the next section		

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9. Did you receive marketing material about both of ISO New England's 2002 DR program opportunities?
- a. Yes
 - b. No – only the Demand Response Program (Class 1)
 - c. No – only the Price Response Program (Class 2)
 - d. Don't know or recall
10. Please rate the marketing material for the following attributes, on a scale of 1 to 5, with **5 being the highest**?
- a. Provided key program information in a straightforward and easy to understand manner
 - b. Provided just the right amount of information about each program
 - c. Program benefits were clearly noted
 - d. Program benefits addressed the key benefits to participating in the program for your company
 - e. Was useful in helping to make decision to participate
 - f. Motivated your company to participate
 - g. Clearly explained how to enroll
 - h. Written for the correct decision maker in your company
-
-

Sign-up/Enrollment Process

1. Overall, how would you rate the sign-up/enrollment process?
- a. Excellent
 - b. Good
 - c. Average
 - d. Fair
 - e. Poor
2. Did you receive adequate information about the enrollment process?
- a. Yes
 - b. No
 - c. Don't know
3. Did you find the sign-up/enrollment process to be straightforward?
- a. Yes
 - b. No
 - c. Don't know
4. Was it clear who to contact for questions or to resolve issues regarding sign-up/enrollment?
- a. Yes
 - b. No
 - c. Don't know

KEY: Check Box- Click Drop-down Box – Select Text Box – Type over black area

5. Who led you through the sign-up/enrollment process?
- a. Your local electric company
 - b. Competitive energy supplier
 - c. Other service provider
 - d. Other -please specify: _____
6. How satisfied were you with the support they provided?
- a. Extremely
 - b. Very
 - c. Somewhat
 - d. Marginally
 - e. Not satisfied
-

Program Operation

1. How easy were the program rules and procedures to understand?
- a. Extremely easy
 - b. Very easy
 - c. Easy
 - d. Marginally easy
 - e. Not easy
2. How did you receive the program rules and procedures?
- a. Both verbally and in writing
 - b. In writing only
 - c. Only verbally
 - d. Not at all
 - e. Electronically (Email or Website)
3. If you received written program rules and procedures, who supplied them?
- a. They were supplied by:
 - i. Your local electric company
 - ii. Competitive energy supplier(s)
 - iii. Other service provider
 - iv. ISO New England
 - v. Your state public utility commission
 - vi. Other
 - b. I did not receive them
4. Did the rules/procedures make sense to you in terms of why they were necessary?
- a. Yes
 - b. No – please explain _____
 - c. Don't know
 - d. How would you rate the program payment/settlement process?
 - i. Excellent
 - ii. Good
 - iii. Average
 - iv. Fair
 - v. Poor
 - vi. Don't Know

KEY: Check Box- Click Drop-down Box – Select Text Box – Type over black area

5. How satisfied are you with the metering requirements?

- a. Extremely satisfied
- b. Very satisfied
- c. Satisfied
- d. Marginally satisfied
- e. Not satisfied
- f. Don't know

6. Did you receive operational information from RETX?

- f. Yes - please rate the usefulness of the information:
 - i. Extremely useful
 - ii. Very useful
 - iii. Somewhat useful
 - iv. Marginally useful
 - v. Not useful
- g. No – would you have liked to receive information?
 - i. Yes
 - ii. No
 - iii. Don't know
- h. Not applicable – did not use RETX
- i. Don't know

7. Were you told who to contact for questions?

- a. Yes
- b. No
- c. Don't know

7. Please indicate whether you called or attempted to contact any of the following entities with questions and if so please rate - **on a scale of 1 to 5** - how helpful and responsive they were, with being **5 extremely helpful/responsive**.

	Entity Called	Helpful/Responsive
a.	<input type="checkbox"/> Local electric company	<input type="text"/>
b.	<input type="checkbox"/> Competitive energy supplier	<input type="text"/>
c.	<input type="checkbox"/> Other service provider	<input type="text"/>
d.	<input type="checkbox"/> ISO New England	<input type="text"/>
e.	<input type="checkbox"/> RETX	<input type="text"/>
f.	<input type="checkbox"/> State Public Utility Commission	<input type="text"/>
g.	<input type="checkbox"/> Trade Association	<input type="text"/>
h.	<input type="checkbox"/> Other - please specify _____	<input type="text"/>
i.	<input type="checkbox"/> Did not make any calls	<input type="text"/>

8. Overall, how customer friendly was the whole process?

- a. Extremely
- b. Very
- c. Somewhat
- d. Marginally
- e. Not

KEY: Check Box- Click Drop-down Box – Select Text Box – Type over black area

2002 Curtailment - Price Response Program (Class 2) Participants Only

Note: If you participated in the 2002 Demand Response Program (Class 1) skip to the next section.

1. Did you participate in any Price Response Program (Class 2) curtailment event during this past summer?
 - a. Yes
 - b. No – please explain why not _____
_____ **skip to next section**
2. Was the curtailment notification time period sufficient for your company to respond to an event notice?
 - a. Yes
 - b. No. Please specify a better time period: _____
 - c. Don't know
 - d. Not applicable – please explain _____
3. Which of the following curtailment notification methods did you rely on this year to hear about program curtailment events (*check all that apply*)?
 - a. e-mail
 - b. pager
 - c. automated phone call
 - d. fax
 - e. other – please specify: _____
4. Please indicate which of the following curtailment notification method(s) you prefer (*check all that apply*).
 - a. e-mail
 - b. pager
 - c. automated phone call
 - d. fax
 - e. other – please specify: _____
5. Would you desire multiple notification methods per employee notified?
 - a. Yes
 - b. No
 - c. Don't know
6. Do you believe you received notification of all Price Response events?
 - a. Yes
 - b. No
 - c. Don't know
7. How would you rate the content in the notification message itself? How would you modify it, if at all?
 - a. Rating:
 - i. Excellent
 - ii. Good
 - iii. Adequate
 - iv. Fair
 - v. Poor
 - b. How would you modify it, if at all? _____

KEY: Check Box- Click	Drop-down Box – Select	Text Box – Type over black area
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8. Did you monitor the price forecast during the program in anticipation of curtailment events?
- Yes
 - No
 - Don't know
9. On a scale of 1 to 5, with 5 being the greatest, to what extent did TV or radio newscasts impact your decision to participate in an event?
10. Please indicate how many Price Response Program events you participated in?
11. If you were unable to participate in an event after enrolling in the program please tell us why and during which period of time the event took place (*check all that apply*):
- | | Jun/July | Aug/Sept |
|---|--------------------------|--------------------------|
| a. Did not receive notice in time | <input type="checkbox"/> | <input type="checkbox"/> |
| b. Had not received payment for previous event(s) | <input type="checkbox"/> | <input type="checkbox"/> |
| c. Could not reduce load as planned | <input type="checkbox"/> | <input type="checkbox"/> |
| d. Unable to use on site generator as planned | <input type="checkbox"/> | <input type="checkbox"/> |
| e. Insufficient personnel | <input type="checkbox"/> | <input type="checkbox"/> |
| f. Plant already closed | <input type="checkbox"/> | <input type="checkbox"/> |
| g. Expected payment amount insufficient | <input type="checkbox"/> | <input type="checkbox"/> |
| h. Other – please specify _____ | | |
12. Please note which major actions your company took to curtail load (*check all that apply*).
- Turned off lights
 - Adjusted temperature or shut off air conditioning
 - Adjusted temperature or shut off refrigeration
 - Adjusted temperature or shut off water heating
 - Reduced or shut off office equipment
 - Halted or reduced production process(es)
 - Shut down office/plant by
 - 25%
 - 50%
 - 75%
 - 100%
 - Operated on-site generator
 - Shed load via the EMS system
 - Coordinated curtailment with other facilities/companies
 - Other please specify _____
13. Would you take any different actions in the future? And if so what actions?
- Yes, we would _____
 - No
 - Don't know

KEY: Check Box- Click Drop-down Box – Select Text Box – Type over black area

Financial/Operational

1. Was there any incremental increase in operating expense resulting from load interruption or availability for interruption? If yes please provide an approximate dollar amount
 - a. Yes we experienced an increase of approx:
 - i. \$ _____ /day **or**
 - ii. \$ _____ /hour **or**
 - iii. \$ _____ /MWH
 - b. No
 - c. Don't know
 - d. No comment
 - e. Not applicable please explain _____
2. Was there any incremental decrease in operating revenue resulting from load interruption or availability for interruption? If yes please provide an approximate dollar amount.
 - a. Yes we experienced a decrease of approx.
 - i. \$ _____ /day **or**
 - ii. \$ _____ /hour **or**
 - iii. \$ _____ /MWH
 - b. No
 - c. Don't know
 - d. No comment
 - e. Not applicable please explain _____
3. Did you experience any adverse impact of program participation in addition to the costs reported above?
 - a. Yes - please specify _____
 - b. No
 - c. Don't know
4. Did you experience any loss of amenities (e.g. comfort, convenience) as a direct result of program participation? If so, please rank the loss on a scale of 1 to 5 - with 1 being a very small loss and **5 being an extremely high loss**.
 - a. Yes - please rank:
 - b. No
 - c. Don't know
5. Did you experience any benefits of program participation in addition to the program incentive payments?
 - a. Yes - please specify _____
 - b. No
 - c. Don't know

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6. If your facility were to experience an unplanned total power outage for two hours in the afternoon on a weekday what would be the estimated value of the economic loss experienced at your facility?
- a. 0 to \$ 499
 - b. \$ 500 to \$ 999
 - c. \$ 1,000 to \$ 4,999
 - d. \$ 5,000 to \$ 9,999
 - e. \$ 10,000 to \$ 19,999
 - f. \$ 20,000 to \$ 39,999
 - g. \$ 40,000 to \$ 59,999
 - h. \$ 60,000 to \$ 79,999
 - i. \$ 80,000 to \$ 999,999
 - j. \$ 100,000 or more - please specify \$ _____, and indicate the nature of the economic loss _____
 - k. Don't know
7. Does your company have a specific economic goal or requirement for participation in a demand response program event?
- a. Yes - please specify _____
 - b. No
 - c. Don't know
 - d. No comment
8. What simple pay back period would your company require for an investment to improve your facility's capability to manage load?
- a. Would not make such an investment
 - b. Less than 1 year
 - c. Less than 2 years
 - d. Less than 3 years
 - e. Less than 5 years
 - f. Less than 7 years
 - g. Less than 10 years
 - a. Other investment criteria, please describe _____
 - b. No specific investment criteria applies this kind of investment
9. Were you required to obtain any special governmental permits/licenses in order to participate in the program?
- a. Yes - please specify _____
 - b. No
 - c. Don't know

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10. Which of the following equipment did you install or receive specifically to participate in the program? *(check all that apply)*
- a. Communications equipment/Notification technologies
 - b. Internet-based meter-reading
 - c. Interval meter and/or pulse initiator at service entrance
 - d. Interval sub-meters at major loads
 - e. Load control devices for lighting
 - f. Load control devices for equipment
 - g. Energy management system
 - h. New on-site generators
 - i. Enhanced existing on-site generators (e.g. parallel switchgear)
 - j. Other please specify: _____
 - k. None **skip to next section**
11. How was the cost for the equipment and installation funded?
- a. Our company paid 100 percent of the cost
 - b. Our company paid a portion of the cost
 - c. The material and installation was done at no cost to us
12. If some portion of the costs were funded by another entity, who was that entity?
- a. Local electric utility
 - b. Competitive energy supplier
 - c. Other service provider
 - d. Other, please describe _____
 - e. Not applicable
13. Did you encounter any physical challenges when installing the equipment?
- a. Yes please explain: _____
 - b. No
 - c. Don't know
14. What were the overall incremental costs associated with new equipment and its installation other than on site generation? *(If you received an incentive please include those dollars in the incremental costs)*
- a. \$ _____
 - b. Not applicable
 - c. Don't know
 - d. No comment
15. What were the overall incremental costs to participate related to on site generation? *(If you received an incentive please include those dollars in the incremental costs)*
- a. \$ _____
 - b. Not applicable
 - c. Don't know
 - d. No comment

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Future Programs

1. Do you plan to enroll in the 2003 programs?
 - a. Yes
 - b. Don't know
 - c. No please explain: _____

skip to next section
2. How would you rate the following program features in terms of enhancing Demand Response program acceptance: (please respond with **Essential, Highly desirable, Desirable, Indifferent, Undesirable, or Don't know**)
Features:
 - a. Ability to reselect a new program type or format monthly
 - b. Ability to trade or sell a monthly DR capacity credits
 - a. Multiyear paym't guarantees independent of curtailment frequency
 - c. Air emissions permitting assistance for standby generators
 - d. Reduced standby generator retail tariff back-up requirements
 - e. Free facility load management potential assessments
 - f. Financing or incentives for load management infrastructure technology investments
3. Do you understand why performance penalties are required for failure to initiate contracted load reductions when notified by ISO New England?
 - a. Yes
 - b. No
4. Assuming the economic value of demand response in the power market is maximized when it can perform with the same dependability as conventional peaking or fast response generation resources, under what terms, conditions and/or circumstances would your Company be willing to accept a penalty provision for any program under performance (such as, failure to reduce load by a lesser amount than what was previously agreed to)? _____

There are generically two types of Demand Response programs available for retail customers to participate in:

- Emergency Programs
Emergency programs are called upon to avoid blackouts and/or involuntary load shedding (i.e. when the demand for electricity has reached a point where the supply is insufficient to meet that demand and maintain an adequate level of operating reserve). Historically, this type of program is called upon very few times per year.

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- Economic Programs
Economic programs are called upon to contain energy prices and reduce air emissions. They are called upon when the real time (spot) energy market price reaches a level where demand response resources can be a viable cost alternative to higher cost of peak generation resources. Trigger points for economic demand response programs can be the result of submitted bids or pre-determined energy market price levels. Historically, these types of programs are called upon more frequently (i.e. in 2002 they were called upon 12 times).

5. Based on the generic demand response programs described above, would you be more likely to:
- a. Participate only in an Emergency type program
 - b. Participate only in an Economic type program **skip to Question 7**
 - c. Participate in either type of programs, depending on potential for an economic gain
 - c. Not participate at all in either program type, please explain _____ **skip to next section**
 - d. Don't know
6. If more likely to participate in an Emergency Type Demand Response program would you prefer a guaranteed minimum compensation payment per event?
- a. Yes. If so please describe _____
 - b. No
 - c. No opinion

If not interested in an Economic Type Demand Response Program ...Skip to Question 8

7. If more likely to participate in an Economic Type Demand Response Program you would prefer to:
- a. Be called on to reduce load when the Real Time energy market price hits a pre-established level set for the program by the ISO
 - b. Bid into the energy market on a Day Ahead basis above a pre-established minimum bid price, but below a pre-established maximum bid price set by the ISO
 - c. Bid into the energy market on a Day Ahead basis with out a pre-established minimum or maximum bid price
 - d. Be called on to reduce load only when the Real Time energy market exceeds a pre-established level you set weekly or on a less frequent biases
 - e. No opinion
8. Assuming your economic reward for participating in a demand response program was met how many times per year would you be willing to drop at least 100 kW of load?
- a. 1 to 5
 - b. 6 to 10
 - c. 11 to 15
 - d. more than 15

KEY: Check Box- Click Drop-down Box – Select Text Box – Type over black area

9. Assuming your economic reward for participating in a demand response program was met how long of a load reduction could you typically manage per called event?
- a. Less than 2 hours
 - b. 2 hours
 - c. 3 to 4 hours
 - d. 5 to 6 hours
 - e. up to 8 hours
 - f. more than 8 hours
10. How much notice time would you require to reduce beyond what you currently agreed to?
- a. 30 minutes or less
 - b. 31 minutes to 1 hour
 - c. more than 1 hour but less than 2 hours
 - d. more than 2 hours but less than 8 hours
 - e. more than 8 hours
 - f. Not applicable – we can not reduce more
 - g. Don't know
11. If you received the notice time you selected in question 9 above, how much would you be able to reduce above your current agreed to level?
- a. We could reduce load an additional _____kW
 - b. None
 - c. Don't know
12. What is the best time of day to be notified of a demand response event for that day?
- a. 6 -8 a.m.
 - b. 9-10 a.m.
 - c. 11-12 noon.
 - d. 1-2 p.m.
 - e. 3-4 p.m.
 - f. 5-6 p.m.
 - g. other please specify _____

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Business Characteristics

Please answer the following questions based on your building(s) which participated in the program:

1. Which of the following best describes your type of business?
 - a. Commercial – office
 - b. Commercial – retail
 - c. Industrial – manufacturing
 - d. Industrial – office
 - e. Government
 - f. Health Services
 - g. Wholesale trade
 - h. Lodging
 - i. Entertainment (e.g. restaurant, casino)
 - j. Education
2. Please check the kinds of equipment are used in your business?
 - a. Lighting
 - b. Space conditioning (HVAC)
 - c. Refrigeration
 - d. Manufacturing and process equipment
 - e. Cooking or other food preparation equipment
3. Do you own or lease your space?
 - a. Own
 - b. Lease
4. What are your typical hours of operation?
 - a. Weekdays only- single shift
 - b. Weekdays only- multiple shifts
 - c. Weekdays and weekend days-single shift
 - d. Weekdays and weekend days-multiple shifts
 - e. 24/7
5. Approximately how many people work at this facility? _____
6. Approximately how many square feet of conditioned space (heated/cooled) does the facility have? _____
7. What is the approximate age of the building(s)? _____
8. Was an Energy Management System (EMS) system or were process controls already installed in the buildings/facility?
 - a. Yes
 - b. No
 - c. Don't know
9. What is (in dollars) your approximate monthly electric bill? _____
10. What percentage of your total annual operating or production expense is your electric bill? _____
11. What was the maximum hourly monthly electrical demand (within the prior 12 month period) at your facility? _____

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12. During what hours of the day do you use electricity the most? (please note the hour and circle either am or pm)
- a. From _____ am/pm to _____ am/pm
13. What types of fuels are also used in your buildings?
- a. Gas
- b. Oil
- c. Propane
- d. Other please specify: _____
14. Did or is your company currently participating in any utility offered Conservation and Load Management Program?
- a. Yes
- b. No
- c. Don't know
15. Have you conducted a technical assessment of your facilities' potential to actively manage electrical load and or made any other load management related investments not noted above in the Financial/Operational Section within the last three years.
- a. Yes – we conducted both a technical assessment and made load management related investments
- b. Yes – we conducted a technical assessments
- c. Yes and made load management related investments
- d. No – **skip to next section**
16. How was the technical assessment and/or load management investment funded?
- a. Our company paid 100 percent of the cost
- b. Our company paid a portion of the cost
- c. The assessment/investment was done at no cost to us
17. If some portion of the costs were funded by another entity, who was that entity?
- a. Local electric utility
- b. Competitive energy supplier
- c. Other service provider
- d. Other, please describe _____
- e. Not applicable
18. If a technical assessment was performed what percentage of the recommendations were implemented?
- a. 100% - **skip to the next section**
- b. 75%
- c. 50%
- d. 25%
- e. less than 25%
- f. None
- g. Not applicable

KEY: Check Box- Click Drop-down Box – Select Text Box – Type over black area

19. Please note the major reasons for not implementing all of the recommendations.
(check all that apply)

- a. Insufficient time to do the needed work
- b. Not cost effective or did not meet our investment criteria
- c. Would have liked to implement, but capital was unavailable
- d. Did not seem consistent with our operational requirements
- e. Plan to implement more recommendations in the future
- f. Not applicable

General Satisfaction

1. Overall, how satisfied were you with the 2002 Demand Response Program?
 - a. very satisfied
 - b. somewhat satisfied
 - c. satisfied
 - d. somewhat dissatisfied (please explain: _____)
 - e. very dissatisfied (please explain: _____)
2. Overall, how satisfied were you with ISO-New England's program support?
 - a. very satisfied
 - b. somewhat satisfied
 - c. satisfied
 - d. somewhat dissatisfied (please explain: _____)
 - e. very dissatisfied (please explain: _____)
3. How would you rate the company that signed you up for the program in the following support categories (please respond with **Excellent, Good, Average, Fair, Poor or Not applicable**):
 - a. Communication of the program rules and requirements _____
 - b. Communication of site requirements for participation _____
 - c. Technical expertise in metering installation _____
 - d. Technical expertise in EMS/Load Management _____
 - e. Timeliness in making incentive payments _____
 - f. Helpfulness in procuring site permits _____
4. If you used the RETX system, how would you rate their support in the following categories (please respond with **Excellent, Good, Average, Fair, Poor or Not applicable**): (if you did not use RETX please skip to the next section)
 - a. Understanding of the operational procedures _____
 - b. Understanding of the program site requirements _____
 - c. Technical expertise _____
 - d. Metering equipment quality _____
 - e. Metering equipment ease of installation _____
 - f. Timeliness and responsiveness _____
5. Do you believe your participation this past summer was useful to help address you local power supply issues?
 - a. Yes
 - b. No
 - c. Don't know

KEY: Check Box- Click Drop-down Box – Select Text Box – Type over black area

Comments

We are very interested in any additional comments that you may have. Please use this space to add anything else:

Contact Information

Thank you for completing this survey. Your information will be very helpful in enhancing the ISO NE programs. To receive your survey gift certificate, please fill in your name and address information below and indicate your preference:

Name: _____
Title: _____
Company: _____
Address: Street: _____
City: _____ State: _____ Zip: _____

Email: _____
Phone: _____

Please send me a \$25 gift certificate for

- Home Depot**
 Staples

Would you be willing to participate in an additional follow-up phone call? _____
Would you be willing to participate in any planning sessions regarding future Demand Resource Programs? _____

Please fax your completed survey back to Michael Townsley at: (860) 388-6599

We at the Townsley Consulting Group hope you found this survey easy to use and wish you a nice day!

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ATTACHMENT B

PARTICIPANT SURVEY – RAW RESULTS