December 30, 2005

Via Hand Delivery

Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: Independent Assessment of Demand Response Programs of ISO New England Inc., Docket No. ER02-2330-___

Dear Ms. Salas:

On June 6, 2003, the Federal Energy Regulatory Commission ("Commission") issued an order in the above-referenced docket which, among other things, directed ISO New England Inc. (the "ISO") to "prepare and submit an 'independent' in-depth process and impact evaluation and market assessment of its 2003 demand response programs by December 31, 2003, and to provide a similar evaluation by the end of each calendar year until and including December 31, 2005."[1] As in 2004, the ISO has retained RLW Analytics, LLC and Neenan Associates, LLC to conduct this annual evaluation and assessment.

These consultants have produced the report that is Attachment 1 hereto, entitled "An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2005." The report contains descriptions of each of the demand response programs, descriptions of program participation and performance, an analysis of the market impacts of the programs, a comprehensive process evaluation (including an assessment of customer satisfaction and preferences), and a market assessment.

Pursuant to Rule 1907 of the Commission's Rules of Practice and Procedure,[2] the ISO hereby submits an original and 5 copies of this letter and its attachments in accordance with the

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[1] *New England Power Pool and ISO New England Inc.,* Order on Rehearing and Accepting in Part and Rejecting in Part Compliance Filings, 103 FERC ¶ 61,304 at P 69 (June 6, 2003) ("June 6 Order").

[2] *See* 18 C.F.R. § 385.1907 (2005).

June 6 Order. Paper copies of this letter and report are being served on all persons on the Commission's official service list in the captioned proceeding. All NEPOOL Participants Committee members (as listed in Attachment 2) are being furnished with an electronic copy of this letter and report, and the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area (also listed in Attachment 2) are being furnished with paper copies. In accordance with the Commission's rules and practice, there is no need for these entities to be included on the Commission's official service list in this proceeding unless such entities already are or become intervenors in this proceeding.

Respectfully submitted,

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Attachments

cc: All parties to FERC Docket No. ER02-2330

ATTACHMENT 1

An Evaluation of the Performance of the Demand Response Programs Implemented by ISO-NE in 2005

Prepared for:

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Prepared by:

RLW Analytics, LLC

Neenan Associates, LLC

December 30, 2005

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ISO-NE 2005 Demand Response Program Evaluation

1 Introduction

1.1 Overview

ISO New England Inc. (ISO-NE) commissioned the team of RLW Analytics and Neenan Associates to conduct a comprehensive evaluation of ISO-NE's demand response programs. This evaluation was conducted to comply with a June 6, 2003 Order issued by the Federal Energy Regulatory Commission, which directed ISO-NE to prepare and submit an annual independent evaluation of its demand response programs at the end of each calendar year through December 31, 2005. This evaluation is comprised of four main elements:

- A market impacts evaluation,
- A process evaluation study,
- An assessment of customer satisfaction, and
- A market assessment study.

The market impacts evaluation quantified the benefits from load curtailments undertaken during program events. To estimate market price impacts from the Real-Time Price Response Program, Neenan Associates constructed an economic supply model of the New England wholesale market. The economic model provides the means for estimating how wholesale market prices are impacted during price response events, and projects the impacts of those wholesale market price changes into bill savings realized by the buyers of electricity. Another model was developed that estimates the reliability benefits associated with load curtailed by participants in the Real-Time Demand and Profiled Response Programs.

The process evaluation study identified the procedures and processes involved in implementing the programs and evaluated how well ISO-NE performed these functions. The primary sources of data for the process evaluation were surveys and in-person interviews with ISO-NE staff and other stakeholders, as well as reviews of program manuals and records.

Customer satisfaction was evaluated by conducting an on-line survey of retail customers participating in the programs, as well as the companies that enroll and provide demand response services to these retail customers.

The market assessment study evaluated the potential for promoting price responsive demand in New England using Day-Ahead Indexed Default Service (DADS). The assessment used primary and secondary sources to define the market for DADS, which consisted of commercial and industrial (C&I) load with peak demands of 100 kW or greater. The load data was segmented into five different business classes and price elasticities were developed for each of the business classes to estimate the potential for price responsive demand.

This document is organized in the following manner:

- Section 1 provides an overview of this evaluation report and a description of the various demand response programs administered by ISO-NE in 2005.
- Section 2 discusses the programs' participation and performance.
- Section 3 presents the programs' market impacts.
- Section 4 presents the results of the process evaluation including the findings from the stakeholder and customer surveys.
- Section 5 estimates the market potential of price responsive demand in New England.

1.2 Program Descriptions

ISO-NE's demand response programs were first introduced in March 2003 concurrent with the introduction of Standard Market Design. The programs, which replaced the existing ISO-NE offerings that had been available since 2001, are organized into two general categories, as follows:

- **Reliability Programs** provide capacity (kW) and energy (kWh) resources that are available within either 30-minutes or 2-hours of ISO-NE's request during periods of emergencies on the electricity grid. These programs include the Real-Time Demand Response Program the Real-Time Profiled Response Program ("Reliability Programs").
- **Price Programs** encourage customers to reduce energy (kWh) consumption during periods of high Real-Time or Day-Ahead wholesale energy prices. These programs include the Real-Time Price Response Program ("Price Program") and Day-Ahead Load Response Program ("Day-Ahead Option").

Retail customers enroll in a program through an Enrolling Participant, which can be a local distribution company, competitive energy service provider, or independent Demand Response Provider.[1] The programs are described in the following sections. Complete details of the ISO-NE demand response programs can be found in the program manuals available at the ISO-NE web site (www.iso-ne.com).

1.3 Real-Time Demand Response Program

The Real-Time Demand Response Program is designed for customers that can reduce their electricity usage within either 30 minutes or two hours of a request by ISO-NE. These requests are called "Reliability Events." Compliance with reliability events, which coincide with ISO-NE Operating Procedure No. 4 (OP-4) conditions, is mandatory.[2] OP-

[1] Demand Response Providers are entities that are not New England Power Pool (NEPOOL) Participants and that aggregate and enroll curtailable loads into the demand response programs.

[2] OP-4 defines the actions taken during a capacity deficiency. The first ten actions of OP-4 are implemented to maintain operating reserves. Later actions of OP-4, Actions 11 through 16, represent more extreme dispatch actions and may result in degraded system reliability since full operating reserve required

4 events occur when there is an expected shortfall in reserve resources on the wholesale electricity grid. Participants that reduce their consumption during the reliability events are paid the greater of the Real-Time Locational Marginal Price (LMP) applicable to their Load Zone or a Floor Price. The Floor Price is $0.50/kWh for participants that agree to respond within 30 minutes and $0.35/kWh for those that agree to respond within two hours. ISO-NE guarantees a minimum of two hours of curtailment for each reliability event. Participants in this program are also eligible to earn installed capacity (ICAP) credits. The quantity (MW) of a participant's ICAP credit is based on their enrolled (committed) reduction or actual performance in a reliability event. Failure to reduce load during a reliability event results in the forfeiture of ICAP credit earned for the month in which the reliability event occurred. In addition, the participant's ICAP credit in the months following the reliability event is de-rated accordingly. Enrolling Participants can monetize the ICAP credits in several ways, including by offering the credits into the monthly ICAP Supply Auction, using the ICAP credits to offset an ICAP obligation and, in the case of certain resources in Southwest Connecticut, through a Supplemental Capacity Agreement with ISO New England.

Table 1-1 summarizes the characteristics of the Real-Time Demand Response Program.

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or normal operation is not maintained. For example, at Action 11 of OP-4, ISO-NE will allow the 30-minute operating reserve to decrease to zero.

Program Feature	**Description**
Eligible Retail Customers	Individual or Groups (Minimum 100 kW Reduction).
Program Activation	Respond to ISO Control Room Request.
Required Response Time	Within 30-Minutes or 2-Hours of ISO request.
Energy Payment	Greater of Real-Time LMP or Guaranteed Minimum $0.50/kWh for 30-Minute Response and $0.35/kWh for 2-Hour Response.
Capacity Payment	Monthly payment ($/kW) based on the ICAP Supply Auction and/or Supplemental Capacity Agreement.
Minimum Event Duration	Minimum 2-Hour guaranteed interruption.
Metering Requirement	5-Minute Usage data sent to ISO-NE via the Internet or customized monitoring and verification plan.

Table 1-1: Real-Time Demand Response Program Features

The Real-Time Demand Response Program is activated at different Action Steps of OP-4 depending on the program's notification time and the technology used by the participating customer to accomplish the load reduction. The Action Steps, Notification Times, and Technologies are described in the Table 1-2.

Allowed Notification Time	**Technology**	**OP-4 Action Step**
30-Minutes	Load Reduction with or without Emergency Generation[3]	Actions 9 and 12
2-Hours	Load Reduction with or without Emergency Generation	Actions 3, 4, 5, 7, and 8

Table 1-2: Real-Time Demand Response Program Activation Description

Participation in the Real-Time Demand Response Program requires the installation of special metering and communication systems capable of recording the participant's

[3] While each state in New England has slightly different environmental rules, typical emergency generator operating permits will only allow such generators to operate following ISO-NE declaration of OP-4 Action 12 (implementation of voltage reductions) or following the loss of external power to the facility. Therefore, such emergency generators must be in the Action 12 portion of the 30-minute notice program to avoid violating their operating permit.

electricity consumption in five-minute intervals. These metering and communication systems are referred to as Internet Based Communication Systems (IBCS). ISO-NE's IBCS system is an open-architecture system – called the IBCS Open Solution or IBCS OS – which allows a variety of vendors to provide participating customers with IBCS services. Meter data, reliability event notification messages, and other data are transmitted via the Internet between ISO-NE and Enrolling Participants and participating customers through the IBCS-OS.

NEPOOL provides financial subsidies to help program participants offset all or a portion of the costs to purchase, install, and maintain metering systems that meet the IBCS requirements. The equipment incentive can be up to $2,800 per facility, depending upon installation requirements and the level of committed load reduction. Financial incentives are available on a prorated basis for facilities that commit as little as 25 kW in load reduction. Participants that commit a load reduction of 300 kW or greater also receive up to $100 per month towards the cost of maintaining the IBCS.

1.4 Real-Time Price Response Program

The Real-Time Price Response Program provides financial incentives to participating retail customers for voluntary load reductions when ISO-NE activates a price event. Price events are activated when either an hourly Day-Ahead LMP or a forecasted hourly LMP is greater than or equal to $0.10/kWh during the hours of 7 a.m. to 6 p.m. on non-holiday weekdays.[4] ISO-NE notifies retail customers and their Enrolling Participants of price events by e-mail. ISO-NE typically makes the determination to open a price event late in the day prior to the event day. Once the price event is opened, ISO-NE is authorized to make payments for any load that is curtailed during the entire 11-hour period. However, program rules also permit ISO-NE to declare an event on the same day, or for a shorter period. Section 1.7 of this report contains a more detailed

[4] ISO-NE opens the eligibility period in a Load Zone when actual Day-Ahead or Real-Time LMPs as forecasted by a Resource Adequacy Analysis for that Load Zone equals or exceeds $100/MWh during the eligible hours (7:00 a.m. to 6:00 p.m.).

description of the event triggering method and event start and end times. Participating customers are paid the greater of $0.10/kWh or the Real-Time LMP in their Load Zone for voluntary load reductions during price events. Unlike participants in the Reliability Programs, participating customers in the Real-Time Price Response Program do not earn a monthly capacity or ICAP credit.

Table 1-3 summarizes the characteristics of the Real-Time Price Response Program.

Program Feature	**Description**
Eligible Retail Customers	Individual or Groups (Minimum 100 kW Reduction).
Program Activation	Notified by ISO-NE that wholesale prices are forecasted to exceed $0.10/kWh either the night before or morning of the event day.
Required Response Time	The program is 100% voluntary. Participating retail customers decide when and for how long they participate.
Energy Payment	Greater of Real-Time LMP or Guaranteed Minimum of $0.10/kWh.
Capacity Payment	None
Minimum Event Duration	Price response "window" can open as early as 7AM and remains open until 6PM.
Metering Requirement	The minimum requirement is a meter capable of recording a retail customer's hourly usage. Customized Monitoring and Verification plans can also be considered.

Table 1-3: Real-Time Price Response Program Features

Historically, price events started at 7:00 a.m. and extended to 6:00 p.m. Starting on March 16, 2005, ISO-NE changed the default price event start time of the program to 2 p.m. to have the event hours better coincide with the periods of high Real-Time LMPs during the winter season. A more detailed description of the price event trigger methodology, as well as the default start and end times, is contained in Section 1.7.1 of this report. Starting with a June 6, 2005 event, ISO-NE changed the default price event start time to noon. The noon default start time remained in effect for the duration of the summer season ending on September 30, 2005.

Enrolling Participants and their participating customers are notified of price response events by e-mail and by a posting on the ISO-NE web site. Some Enrolling Participants notify their program participants of price response events using pagers, automated phone calls, and other means. Meter readings for this program are submitted daily or monthly by the Enrolling Participant to ISO-NE on the same schedule as other hourly meter data.

The Real-Time Price Response Program allows for an alternative data reporting method for customers who do not have daily meter reading capability. This option is referred to as the "Super Low Tech" option. Enrolling Participants are required to submit to ISO-NE hourly data for their Super Low Tech customers prior to the 90-day resettlement period.[5] When the ISO performs the 90-day resettlement of the Real-Time Energy Market, the Enrolling Participants for these resources are paid for verified load curtailments that occurred during event hours.

1.5 Real-Time Profiled Response Program

The Real-Time Profiled Response Program is a Reliability Program for Enrolling Participants with loads that are capable of being interrupted within 2 hours after receiving instructions from ISO-NE to interrupt load. The Real-Time Profiled Response Program is activated at Action Step 3 of OP-4. Individual customers participating in the Real-Time Profiled Response Program are not required to have an interval meter or IBCS. Instead, the Enrolling Participant is required to develop a customized monitoring and verification plan (M&V) plan, under the guidelines specified in Appendix E of the Load Response manual.

The Enrolling Participant is paid the higher of the Real-Time LMP in its Load Zone or a minimum payment of $0.10/kWh for the actual load reduction as determined by the approved M&V plan. Demand Resources that participate in the Real-Time Profiled Response Program are eligible to qualify as ICAP Resources.

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[5] Only data sent to ISO-NE within 60 hours of an event, or true-up data sent before the 20th of the month, are included in the initial settlement. The Enrolling Participants typically send the Super Low Technology customers load data once a month after the deadline for inclusion in initial settlement.

1.6 Day-Ahead Load Response Program

The Day-Ahead Load Response Program ("Day Ahead Option") allows Enrolling Participants with retail customers already enrolled in one of the Real-Time Demand Response Programs to submit an offer concurrent with the Day-Ahead Energy Market to curtail electricity consumption for the following day. The offer would specify a price (which would consist of an offer price in dollars per MWh curtailed and an optional "Curtailment Initiation Price" in dollars per curtailment), the amount of curtailment, and minimum duration over which the retail customer would be willing to reduce consumption. Unlike the Real-Time Demand Response Programs, the Day-Ahead Option is based on electricity prices set in the Day-Ahead Energy Market.

The Enrolling Participant's offers will be compared with the Day-Ahead Energy Market hourly clearing prices in its Load Zone. If the combination of the offer price ($/MWh) and the average Curtailment Initiation Price is less than or equal to the Day-Ahead Energy Market hourly clearing prices, the Enrolling Participant's offer will be accepted, or "cleared."

Enrolling Participant offers must be at least 100 kW per demand response asset, must be submitted in increments of 100 kW, and can be as high as the amount of load that was registered in the Real-Time Price or Demand Response Programs. The price offered must be between $50 and $1,000 per MWh including the average Curtailment Initiation Price. Offers can also specify minimum curtailment duration of up to four hours. Enrolling Participants with offers exceeding 2 MW are subject to financial assurance requirements.

The Day-Ahead Energy Market closes each day at noon, and the results are posted (made available) at approximately 4 p.m. Enrolling Participants are able to check the status of their offers after the results are posted and can notify their retail customers if their individual offer is accepted.

If its offer is accepted, an Enrolling Participant will be paid the higher of the offer price or the hourly Day-Ahead LMP ($/MWh) multiplied by the offer reduction amount (MW) for each hour its offer was accepted. If the Enrolling Participant does not reduce consumption by at least the offer amount when scheduled, the Enrolling Participant is charged the difference between the actual and offered reduction at the hourly zonal Real-Time LMP. If the Enrolling Participant reduces consumption by more than the curtailment offer amount, the Enrolling Participant will be paid the difference between the offer amount and actual reduction at the hourly zonal Real-Time LMP.

Enrolling Participants participating in the Day-Ahead Option with resources enrolled in the Real-Time Demand or Profiled Response program are expected to reduce consumption whenever those programs are activated. If the Enrolling Participant has already reduced consumption because their Day-Ahead offer was accepted, the reduction will count towards their Real-Time Demand or Profiled performance. If the Enrolling Participant's Day-Ahead curtailment offer amount is less than their Real-Time enrolled curtailment, then they are expected to interrupt the full Real-Time enrolled curtailment amount during the event.

Because the Real-Time Price Response Program is voluntary, an Enrolling Participant would not be expected to participate in a price event if it coincides with the period over which their Day-Ahead offer is accepted. If the Enrolling Participant elects to participate in a Real-Time Price Response event, the Enrolling Participant would be paid for any additional voluntary interruption in accordance with the Real-Time Price Response Program rules. However, in no case would an Enrolling Participant be paid twice by ISO-NE for the same reduction.

There are no additional metering and transaction costs to participate in the Day-Ahead Option.

1.7 Major Program Activities

This section provides a detailed discussion of the major program activities during the 2005 program evaluation year, which runs from September 1, 2004 through August 31, 2005. There were two major initiatives undertaken, one involved an effort to improve the accuracy of the event trigger methodology for the Real-Time Price program and the second involved the development of a Demand Response Reserve Pilot program.

1.7.1 Real-Time Price Response Trigger Methodology

Since the implementation of Standard Market Design in New England, ISO-NE has triggered the Real-Time Price Response Program in a Load Zone whenever a single hourly Day-Ahead LMP or a single forecasted hourly Real-Time LMP between the hours of 7 a.m. and 6 p.m. (the default start and end times, respectively, for program events) equals or exceeds $100/MWh. Although not required by the program rules, the default start and end times were used for the large majority of the program events to date.

Several market participants expressed concern that in some hours, Real-Time LMPs have been less than the $100/MWh floor price of the Real-Time Price Response Program during price event hours. At the request of several members of the Demand Response Working Group,[6] ISO-NE conducted an analysis of the Real-Time LMPs versus the Real-Time Price Response Program floor price for the 2004/2005 winter season price events.[7] In its analysis, ISO-NE calculated the frequency distribution of Real-Time LMPs equaling or exceeding the floor price by hour. The frequency distribution revealed a

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[6] The Demand Response Working Group is a subgroup of the NEPOOL Markets Committee.

[7] The analysis focused on the NEMA and Connecticut Load Zones because the vast majority of price response assets are located in these two zones.

higher incidence of Real-Time LMPs below the program floor price during the morning and early afternoon.

Section 2.2.3 of Manual M-LRP – the detailed rules governing ISO-NE's load response programs – gives the ISO the flexibility to start events any time during the period of 7 a.m. to 6 p.m. non-holiday weekdays. The manual requires that all events end by 6 p.m. Section 2.2.3 of Manual M-LRP reads as follows:

> [Customers] will be notified when the forecast hourly Zonal Price is greater than or equal to $100/MWh on a Monday-Friday, non-holidays, (Holidays are listed in OP14, Appendix C), between 7:00 AM – 6:00 PM. *Once notified, the window of availability for Real-Time Price Response can be as early as 7 AM and remain open until 6 PM (i.e., between the hour ending 0800 through the hour ending 1800).*

After consultation with the Demand Response Working Group, ISO-NE changed the default event start time from 7 a.m. to 2 p.m. for the winter season in all Load Zones effective March 17, 2005 to reduce the number of event hours where the Real-Time LMP was less than the Floor Price.

Changing the default start time from 7 a.m. to 2 p.m. significantly reduced the number of event hours where the Real-Time LMP was less than the floor price. The change also resulted in several hours in which the program was not activated where the Real-Time LMP was equal to or greater than the floor price. While there were missed hours in NEMA and Connecticut, capturing those missed hours would have required incurring significant additional event hours in NEMA and Connecticut in which the Real-Time LMP was less than the floor price. In other words, for each missed hour in which the Real-Time LMP exceeded the floor price, approximately 10 hours where the Real-Time

LMP was less than the Floor Price would have been activated in NEMA and Connecticut, respectively.

For the summer season, ISO-NE changed the default start time to noon to capture more of the higher-priced hours that traditionally occur in the early afternoon. ISO-NE is currently investigating alternative methods of triggering the program to improve its efficiency by minimizing the number of overpayment hours while making the trigger mechanism more transparent and practical.

1.7.2 Demand Response Reserves Pilot

ISO New England's proposed Ancillary Service Markets (ASM) design allows for demand response resource participation in the reserves markets. However, the proposed design requires that demand response resources satisfy the same dispatch, metering and size requirements as traditional generation. Specifically all reserve resources, traditional generation and demand response alike, must receive dispatch commands from ISO New England through a Remote Intelligence Gateway (RIG) device, comply with the metering requirements defined in Operating Procedure No. 18 (OP-18), and be at least 5 MW in size. In addition, according to the Northeast Power Coordinating Counsel's (NPCC) Task Force on Coordination of Operations, demand response resources used to satisfy operating reserve requirements must have real-time telemetry.[8]

While the dispatch, metering, and size requirements do not pose a barrier for most large generation resources, they do pose a substantial cost barrier to typical demand response

[8] While NPCC requires **Real-Time** telemetry for resources providing operating reserves, it does not appear that NPCC specifically defines what qualifies as Real-Time telemetry. Individual control areas may be able to exercise discretion in determining the specific technologies and methods that meet the Real-Time telemetry requirement.

resources which are small, numerous, and geographically dispersed throughout New England.[9]

The typical demand response resource in New England is less than 5 MW in size. Demand response resources in the 30-minute and 2-hour Real-Time Demand Response Programs average approximately 2 MW in size. Resources in the Real-Time Price Response Program average about 300 kW. For these smaller, distributed resources, the cost of installing and maintaining a RIG for dispatching and complying with OP-18 real-time metering requirements (that requires data to be submitted in 10-second intervals) is neither economic nor practical.

It is highly unlikely that demand response resources will actively participate in the ASM market given these current market barriers.

To address these barriers, ISO-NE has worked in cooperation with members of the Demand Response Working Group and participants in the NEPOOL Markets Committee to develop a Demand Response Reserves Pilot program ("Pilot"), as described in the sections below, that is designed to test alternative market designs and technologies that will facilitate demand response resource participation in the ASM market. Detailed information on the proposed Pilot was filed with the FERC on September 7, 2005. FERC approved the pilot program in its order dated November 29, 2005.[10]

The Pilot has the following objectives:

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[9] RIG and 10-second SCADA are not cost-effective for small Settlement Only Generators for the same reason.

[10] *See* Amendments to Appendix E of Market Rule 1 to Establish a Demand Response Reserve Pilot Program, Docket No. ER05-1450-000, November 29, 2005.

- To demonstrate whether customer loads can reliably provide Ancillary Service Market products, specifically 30-minute Operating Reserve and 10-minute non-synchronized reserve services.
- To determine the requirements for the level and type of control room communications, dispatch, metering, and telemetry sufficient for demand response resources providing reserve services.
- To identify and evaluate lower cost communications and telemetry solutions that meet the requirements and are more suitable for demand response resources to provide reserves.

To meet these objectives, the Pilot project will focus on two distinct sub-projects with concurrent timelines in order to address two specific issues:

1) Determine the ability of demand response resources to respond to Reserve Activation events as compared to off-line and on-line generation resources.
2) Evaluate lower-cost, two-way communication alternatives to the current combination of Supervisory Control and Data Acquisition (SCADA) and Remote Intelligent Gateway (RIG) technology that is presently required to connect dispatchable resources to the ISO.

The experience gained in the Pilot will help ISO-NE achieve the following long-term goals:

- Allow demand response resources to participate in all wholesale electricity markets (including energy, capacity, and reserves) to the greatest extent possible;
- Ensure that the energy, capacity, and reserve products provided by market resources – i.e., generation and demand response assets – are functionally equivalent with regard to meeting the System Operators' needs; and

- Recognize the behavioral and technological differences between generation and demand response resources to reduce barriers to entry and to encourage all potential resources to participate in as many of the markets as practicable.

ISO New England will solicit a maximum of 50 MW of demand response and "settlement only" generation resources to participate in the Pilot. Resources from among various demand response resource types will be recruited to participate. The demand response resources will be selected to represent the population of demand response resources that would likely participate in a competitive reserve product market. For example, resource types will include but are not limited to weather sensitive loads, non-weather sensitive loads, emergency generation, and load reduction resources.

The Pilot will not affect the quantity or the clearing price of resources acquired through the Forward Reserve Market. Resources participating in the Pilot cannot simultaneously participate in the Forward Reserve Market. Resources participating in the Pilot will be required to register in the Real-Time 30-Minute Demand Response Program. In addition to responding to Pilot events, these resources will also be required to respond to events activated under the Real-Time 30-Minute Demand Response Program.

Real-time performance data from demand response resources participating in the Pilot will be collected and analyzed to:

1) Determine demand response resource usefulness to satisfying system reliability conditions;
2) Determine the requirements and develop a functionally equivalent telemetry option for demand response resource dispatching, communication and telemetry hardware. For example, the Internet Based Communication System Open

Solution currently used for the 30-minute and 2-hour Demand Response Programs will be evaluated as an alternative to the RIG and OP-18 metering requirements.

The results of the Pilot will be used to determine the type(s) of demand response resources that can provide functionally equivalent non-synchronized operating reserves using alternative telemetry. Following the completion of the Pilot, ISO-NE will work in cooperation with members of the Demand Response Working Group and participants of the Markets Committee to integrate demand response resources into the wholesale markets.

2 Program Participation and Performance

The program year 2005 is comprised of the period September 1, 2004 through midnight, August 31, 2005 ("Reporting Period").[11] Program enrollment is measured by number of assets, which are individual customers or aggregations of customers, and by enrolled MW, which is the amount of load those assets committed to the program for curtailment.

2.1 Participation

Table 2-1 provides the enrollment in the Load Response Program by Load Zone as of August 31, 2005, which is divided into two categories: assets that are "Ready To Respond" and assets that have been "Approved" and are pending activation. The numbers in the left portion of the table represent assets that are Ready To Respond and comprise the total potential load reduction as of August 31, 2005. A total of 472.5 MW were enrolled in the Program on August 31, 2005, of which 61 percent were located in the Connecticut Load Zone.

ReadyTo Respond:			Approved:	
Zone	Assets	Total MW	Assets	Total MW
CT	338	289.9	6	3.0
ME	7	49.5	0	0.0
NEMA	112	49.1	2	24.1
NH	7	18.1	0	0.0
RI	82	11.2	8	1.3
SEMA	102	10.9	1	0.1
VT	18	13.6	0	0.0
WCMA	115	30.3	4	0.4
Total	781	472.5	21	28.9

Table 2-1: Enrollment in Load Response Programs by Load Zone

In terms of the number of MW per Load Zone, the ranking of the top three zones remained the same as the corresponding time in the previous year. The total number of Ready To Respond MWs increased from approximately 356 MW in September 2004 to 472 MW in August 2005, an increase of 33% over the period.

[11] This period was selected because of the time needed to process and analyze data in time to meet a Federal Energy Regulatory Commission directive that this report be filed with the Commission by December 31 of each calendar year. Sufficient time was not available to collect and analyze data from later months in the current year.

Table 2-2 below provides the enrollment in the Load Response Program by Load Zone and by program as of August 31, 2005. The numbers provided in Table 2-2 represent assets that are ready to respond and those that have been approved and are pending activation. "Ready To Respond" assets are those that have registered into an ISO-NE load response program, have been approved by ISO-NE for participation, have installed the appropriate metering and communications systems, and have submitted sufficient meter data to ISO-NE to establish a customer baseline (if required). "Approved" assets are those which have registered into an ISO-NE load response program and have been approved by ISO-NE for participation, but have yet to install the appropriate metering and communications systems or to submit sufficient data to ISO-NE to establish a customer baseline. The number of Ready To Respond assets as of August 31, 2005 is 781, an increase of 61 percent over the enrolled assets on August 31, 2004.

Ready To Respond: 781 Assets 472.5 MW						Approved: 21 Assets 28.9 MW				
Zone	**Assets**	**RT Price**	**RT 30-Min**	**RT 2-Hour**	**Profiled**	**Assets**	**RT Price**	**RT 30-Min**	**RT 2-Hour**	**Profiled**
CT	338	40.6	248.7	0.7	0.0	6	0.0	3.0	0.0	0.0
SWCT*	293	3.8	224.8	0.7	0.0	1	0.0	0.1	0.0	0.0
ME	7	37.5	0.0	1.0	11.0	0	0.0	0.0	0.0	0.0
NEMA	112	44.1	2.8	0.8	1.4	2	0.1	24.0	0.0	0.0
NH	7	18.1	0.0	0.0	0.0	0	0.0	0.0	0.0	0.0
RI	82	11.2	0.0	0.0	0.0	8	1.3	0.0	0.0	0.0
SEMA	102	10.4	0.5	0.0	0.0	1	0.1	0.0	0.0	0.0
VT	18	7.5	0.1	0.0	5.9	0	0.0	0.0	0.0	0.0
WCMA	115	21.2	0.1	9.0	0.0	4	0.4	0.0	0.0	0.0
Total	781	190.5	252.2	11.6	18.2	21.0	1.9	27.0	0.0	0.0

Table 2-2: Enrollment by Load Response Program and Load Zone

Table 2-2 indicates that 53% of all program MWs are in the Real-Time 30-Minute Demand Response Program, while approximately 40% are in the Real-Time Price Response Program.

Figure 2-1 illustrates the change in enrollments by program over the past 12 months. Aside from the seasonal retirement of assets from the 30-minute Demand Response Program during the winter months, the graph shows an upward trend in program growth with the exception of the Profiled Response Program. This program had a 65 MW drop in enrolled assets when several large customers were taken off interruptible rates by their local distribution companies in June of 2005 and were subsequently retired from the program. By August of 2005 the total enrolled MWs was about the same as in May of 2005 before the exodus of the Profiled Response Program assets due to increases in both the 30-minute Demand and Real-Time Price Response Programs.

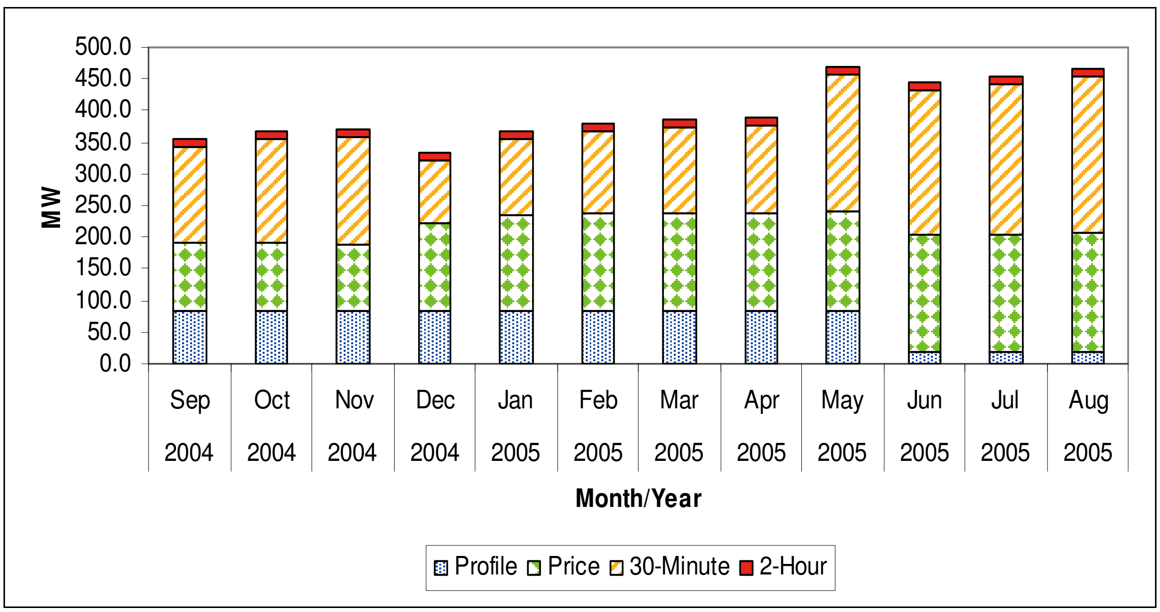

Figure 2-1: Program Enrollment by Month

2.2 Event Statistics

Table 2-3 provides an overview of the Price Program event hours that were called during the Reporting Period in each Load Zone. With the exception of NEMA and CT, all Load

Zones had less than 900 event hours in the Reporting Period. There were 1,099 event hours in NEMA, while in CT there were 919.

Overall, Price Program events were declared on 158 days for a total of 1,143 unique event hours.[12] This represents a significant increase in both the number of events and hours that were called compared to the previous annual evaluation report.

		Number of Hours							
Year	**Month**	**VT**	**NH**	**WCMA**	**RI**	**SEMA**	**ME**	**NEMA**	**CT**
2004	9	11	11	11	11	11	11	11	20
2004	11	66	66	66	66	66	66	76	66
2004	12	132	121	143	143	143	110	198	132
2005	1	165	165	165	165	165	165	176	165
2005	2	75	66	71	66	66	55	66	71
2005	3	54	50	54	54	54	50	83	54
2005	4	44	44	48	40	40	36	72	44
2005	5	12	8	16	12	12	8	60	24
2005	6	59	48	59	59	59	42	111	101
2005	7	96	96	96	96	96	96	108	104
2005	8	138	138	138	138	138	138	138	138
Total		**852**	**813**	**867**	**850**	**850**	**777**	**1,099**	**919**

Table 2-3: Price Response Program Event Summary

The Reliability Programs were activated in Connecticut on July 27th, and the remaining assets were audited for compliance on August 29th. Table 2-4 contains an overview of the different reliability program events that were declared in each Load Zone during the Reporting Period.

Date	Event Type	Load Zone	Programs	Start Time	End Time
July 27, 2005	OP4	CT	30-Minute	1:00 PM	7:15 PM
			2-Hour	1:00 PM	7:15 PM
August 29, 2005	Audit	ME, NEMA, SEMA, WCMA, VT	30-Minute	1:45 PM	4:15 PM
			2-Hour	1:45 PM	5:45 PM
			Profiled	1:45 PM	5:45 PM

Table 2-4: Demand Response Program Event Summary

In accordance with the program rules, ISO-NE conducted a test of the Reliability Programs on August 29, 2005 by activating an Audit Event. Audit Events are conducted in a manner similar to real demand response events – no prior warning was given and

[12] Table 2-3 provides the number of hours in each Load Zone that the program was activated. However, many of these hours overlapped each other. If an event was called in several Load Zones in the same hour, this hour was classified as a "unique" event hour. Thus, the "1,143" unique event hours represents the total number of simultaneous event hours in more than one Load Zone.

participants are not informed of whether the reliability event is an audit or a real OP-4 event. The Audit Event started at 1:45 p.m. and ended at 4:15 p.m. and 5:45 p.m. for customers that elected 30-minutes and 2-hours notice, respectively.

2.3 Program Performance Indices

A measure of performance was calculated to quantify the relative degree of resource performance. The Subscribed Performance Index (SPI) is defined as the actual load curtailed (MWh) during events divided by the amount of load (MWh) that participating customers indicated they would curtail during event hours when enrolling in the program. For example, if a participating customer reduced 1 MW in each hour of a price event that lasted 10 hours, its actual load curtailed would equal 10 MWh. If that same customer had enrolled 2 MW of load in the program, then its expected load reduction for the same 10-hour event would be 20 MWh. Therefore, the customer's SPI would be 10 MWH divided by 20 MWH or 0.50%.

2.3.1 Demand Response Program

ISO-NE's Reliability Programs (i.e., the Real-Time Demand Response and Profiled Response Programs) were activated on two occasions during the Reporting Period: July 27 and August 29. In the former case, ISO-NE declared an OP-4 condition in Southwest Connecticut thereby activating the program for the entire state, but nowhere else in the control area. On August 29th, ISO-NE audited the resources in the programs that had not been activated in the July event.

The information on the July 27th event is contained in Table 2-5. Resources in the Real-Time 30-Minute Demand Response Program are allowed a half-hour to reach their enrolled (committed) load reductions. In the case of the Real-Time 2-Hour Demand Response Program, assets are given a full two hours to reach their enrolled load reduction levels. What this means is that any load curtailment provided between the beginning of the event (1:00 p.m. or HE14) and the time the assets are expected to deliver load reduction (1:30 p.m. for 30-Minute assets and 3:00 p.m. for 2-Hour assets) is of additional value to the system. The same holds true for event hours that continue after 6:00 p.m. (HE18). In the case of events lasting past 6:00 p.m., resources receive energy payments ($/kWh): however resources are not obligated to perform. Thus, Table 2-5 contains the total Enrolled MWs of resources in each Demand Response program, and shows the actual load curtailment these resources achieved (i.e., Actual Performance) as well as the Expected Performance in each hour. Resources in all three Demand Response programs provided Connecticut with nearly 80% of the expected (enrolled) load reductions.

Program	Date	Hour Ending	Enrolled MW	Expected Performance (MWh)	Actual Performance (MWh)	Payments ($)	SPI (%)*
30-Min Demand Response with Emergency Generation	7/27/05	14	182.690	91.345	117.527	$59,067.00	64%
	7/27/05	15	182.690	182.690	153.886	$77,354.00	84%
	7/27/05	16	182.690	182.690	154.431	$77,587.50	85%
	7/27/05	17	182.690	182.690	152.333	$76,539.50	83%
	7/27/05	18	182.690	182.690	151.289	$76,039.50	83%
	7/27/05	19	182.690	0.000	125.331	$63,057.50	N/A
	7/27/05	20	182.690	0.000	12.823	$6,632.50	N/A
Sub-Total			**1,278.830**	**822.105**	**867.620**	**$436,277.50**	**82%**
30-Min Demand Response without Emergency Generation	7/27/05	14	55.050	27.525	27.940	$14,059.50	51%
	7/27/05	15	55.050	55.050	41.032	$20,653.00	75%
	7/27/05	16	55.050	55.050	40.843	$20,553.50	74%
	7/27/05	17	55.050	55.050	39.972	$20,128.50	73%
	7/27/05	18	55.050	55.050	39.028	$19,639.50	71%
	7/27/05	19	55.050	0.000	33.001	$16,617.00	N/A
	7/27/05	20	55.050	0.000	7.293	$3,735.50	N/A
Sub-Total			**385.350**	**247.725**	**229.109**	**$115,386.50**	**71%**
2-Hour Demand Response	7/27/05	14	0.720	0.000	0.300	$111.65	N/A
	7/27/05	15	0.720	0.000	0.400	$146.65	N/A
	7/27/05	16	0.720	0.720	0.680	$243.60	94%
	7/27/05	17	0.720	0.720	0.665	$291.66	92%
	7/27/05	18	0.720	0.720	0.594	$212.10	83%
	7/27/05	19	0.720	0.000	0.590	$207.90	N/A
	7/27/05	20	0.720	0.000	0.140	$52.15	N/A
Sub-Total			**3.600**	**2.160**	**3.369**	**$1,265.71**	**90%**
Grand Total			**1,667.780**	**1,071.990**	**1,100.098**	**$552,929.71**	**79%**

*** SPI is N/A for hours in which a resource was not required to perform (Expected performance= 0); Sub-total and Grand Total SPI values represent the average SPI during only the hours in which a resource was required to perform.**

Table 2-5: July 27th Demand Response Program Performance Indices

The details of the August 29th audit event are contained in Table 2-6. Overall, the resources called for this audit provided an average of 84% of what was enrolled, with some programs performing better than others. Assets in the 30-Minute Demand Response Program using Emergency Generation provided an average of 7% of what was enrolled. Resources in the 30-Minute Demand Response Program that did not use Emergency Generation performed significantly better providing an average of 77% of what was enrolled. Resources in the 2-Hour Demand Response and Profiled Programs provided an average of 75% and 94% of what was enrolled, respectively.

Program	Date	Hour Ending	Enrolled MW	Expected Performance (MWh)	Actual Performance (MWh)	Payments ($)	SPI (%)*
30-Min Demand Response with Emergency Generation	8/29/05	14	0.800	0.000	0.020	$14.500	N/A
	8/29/05	15	0.800	0.600	0.070	$36.500	12%
	8/29/05	16	0.800	0.800	0.061	$32.500	8%
	8/29/05	17	0.800	0.200	0.010	$8.000	5%
Sub-Total			**3.200**	**1.600**	**0.161**	**$91.500**	**7%**
30-Min Demand Response without Emergency Generation	8/29/05	14	2.750	0.000	0.462	$236.000	N/A
	8/29/05	15	2.750	2.063	2.289	$1,144.500	111%
	8/29/05	16	2.750	2.750	2.403	$1,209.000	87%
	8/29/05	17	2.750	0.688	0.358	$184.500	52%
Sub-Total			**11.000**	**5.500**	**5.512**	**$2,774.000**	**77%**
2-Hour Demand Response	8/29/05	14	11.230	0.000	0.060	$21.000	N/A
	8/29/05	15	11.230	0.000	4.660	$1,635.550	N/A
	8/29/05	16	11.230	2.808	6.910	$2,421.300	246%
	8/29/05	17	11.230	11.230	9.600	$3,365.250	85%
	8/29/05	18	11.230	8.423	7.260	$2,543.100	86%
Sub-Total			**56.150**	**22.460**	**28.490**	**$9,986.200**	**75%**
Profiled	8/29/05	14	18.230	0.000	5.450	$1,080.250	N/A
	8/29/05	15	18.230	0.000	5.660	$892.480	N/A
	8/29/05	16	18.230	4.558	14.750	$2,497.990	324%
	8/29/05	17	18.230	18.230	17.610	$2,871.840	97%
	8/29/05	18	18.230	13.673	17.470	$2,331.270	128%
Sub-Total			**91.150**	**36.460**	**60.940**	**$9,673.830**	**94%**
Grand Total			**161.500**	**66.020**	**95.103**	**$22,525.530**	**84%**

*** SPI is N/A for hours in which a resource was not required to perform (Expected performance= 0); Sub-total and Grand Total SPI values represent the average SPI during only the hours in which a resource was required to perform.**

Table 2-6: August 29th Demand Response Program Performance Indices

2.3.2 Real-Time Price Response Program

ISO-NE declared Real-Time Price Response Program events in every month during the Reporting Period, except October 2004. On average, Price Program events were declared 14 days per month during the Reporting Period, as shown in Table 2-7. Real-Time Price Response Program assets provided a total of 45,436 MWh of load relief during the Reporting Period. The number of responding resources steadily grew over the Reporting Period, from 235 assets in September 2004 to 385 in May 2005, but then dropped off considerably between May 2005 and August 2005. Responding resources are those resources enrolling in the program that demonstrated a load reduction during an event hour that was greater than zero.

Year	Month	Event Days	Event Hours	Responding Asset Count	Enrolled (MW)	Performance (MWh)	Payments ($)	SPI (%)*
2004	9	2	97	235	1,470.550	260.014	$26,522.60	17.68%
2004	10	0	0	N/A	N/A	N/A	N/A	N/A
2004	11	7	538	307	8,186.900	2,330.130	$240,235.47	28.46%
2004	12	18	1,122	324	21,311.290	8,124.234	$859,979.57	38.12%
2005	1	16	1,331	332	25,900.600	8,939.104	$938,756.91	34.51%
2005	2	7	536	333	10,215.600	3,158.086	$320,562.70	30.91%
2005	3	12	453	339	9,321.820	2,587.615	$268,844.57	27.76%
2005	4	18	368	347	7,737.920	2,563.707	$263,955.11	33.13%
2005	5	15	152	385	4,086.560	1,530.819	$159,104.07	37.46%
2005	6	21	538	129	14,084.570	3,800.349	$407,249.17	26.98%
2005	7	19	788	129	18,760.380	5,024.615	$675,946.98	26.78%
2005	8	23	1,104	131	26,261.640	7,116.928	$995,376.35	27.10%
Total		**158**	**7,027**	**2,991**	**147,337.830**	**45,435.601**	**$5,156,533.50**	**30.84%**

Table 2-7: Real-Time Price Response Program Performance Indices

Average performance index values were estimated for the Real-Time Price Response Program by month during the Reporting Period and are contained in Table 2-7. Overall, assets in this voluntary program provided 31% of what they enrolled. Between September 2004 and August 2005, the number of responding assets in a given month ranged between 129 and 385. The performance indices also varied across the twelve-month period, from a low of 18% in September of 2004 to a high of 38% in December of 2004. In the month with the highest number of declared event hours (January 2005), the performance index was the third highest of the Reporting Period. Over the period of December 2004 through February 2005, when Price Response events were declared more frequently than in any other three month period during the Reporting Period, the performance indices were at their highest sustained period of the Reporting Period.

3 Market Impacts of ISO-NE's Demand Response Programs

This section of the report will examine the market impacts of both Real-Time Price Response Program and Day-Ahead Option on their respective energy markets. The benefits attributable to the Reliability Programs will also be explained and quantified.

3.1 Benefits of ISO-NE's Demand Response Programs

The goal of ISO-NE's Price Program is to abate the most serious consequences of Real-Time market price volatility, while its Reliability Programs are intended to provide a stock of resources that help avoid electricity shortages. Methods that have been developed specifically to measure the value of demand response were adapted to reflect ISO-NE market circumstances, and then applied to the 2005 program year events. The approach is to simulate what the Real-Time market price would have been if the program curtailments had not been undertaken. Estimates of the programs' benefits were produced by calculating the difference between the simulated and actual Real-Time market prices multiplied by the amount of load that would have paid that price. In addition, the demand response program provides an improvement in reliability, which manifests itself in the reduction of the probability of an outage. Estimating the expected un-served energy and valuing it at a range of different outage costs produced estimates of the reliability benefits. Total program benefits are then compared to payments made to participants to provide an index of program performance.

A reduction in load to be served in Real-Time, all else constant, results in a generating unit (or several units) being backed down from the point at which it otherwise would have operated. Because ISO-NE dispatches units according to an ascending bid supply curve, the market-clearing LMP drops as load drops, all other things equal, and as a consequence buyers in the Real-Time market realize price reductions at that time. The direct benefits, defined as the bill savings realized by purchasers of energy in the Real-Time market, are the product of the reduction in LMP that results from the curtailments and the load purchased in the Real-Time market during the event.

There is an important secondary (indirect) impact of the program on electricity prices in the market. Lower price volatility acts to reduce the premiums that purchasers of bilateral contracts pay. So, they too benefit from the program. These benefits are defined by the product of the reduction in the month's average price resulting from the program times the load transacted through bilateral agreements.

The impact of program curtailments on market prices was estimated by first developing a statistical representation of the relationship between load and LMP in ISO-NE's Real-Time energy market. This supply relationship, which reflects the bid curve that is used to set LMP, was then used to simulate the impact of curtailments on LMP. Event specific price impacts were developed by adding the curtailed load back into the load actually served in each event hour. The intersection of this higher load with the simulated supply curve produces an estimate of the Real-Time price (LMP) that otherwise would have prevailed. The difference between the actual and simulated LMP defines the price change that is used to quantify the direct price effect of load curtailments.

An approximation of the indirect market impact is accomplished by calculating the effect of the Real-Time price changes on the monthly average price, which is lower due to the lower prices during event hours. If the market were perfectly fluid and adjusted instantaneously, then the market would reflect those lower risks through a reduction in the prices that retail suppliers pay for hedge contracts. The product of the reduction in the average price times the amount of load purchased through bilateral contracts provides an estimate of those savings. In reality, markets react with a lag, so while some impacts are realized soon after events, others are felt over subsequent months, or in some cases years.[13]

The degree to which curtailments impact Real-Time LMPs depends on the slope, or steepness, of the supply curve at that time the curtailments are achieved. The steeper the

[13] If the program is successful in reducing price volatility, then retailers will be more inclined to decrease reliance on bilateral market purchases in order to enjoy the benefits of reduced hedging costs through spot market purchases.

curve, the more pronounced the reduction in LMP. The supply flexibility, which is defined as the percentage change in LMP resulting from a one percent change in the load served, is a convenient measure of the impact of load curtailments on the Real-Time market price. The higher the supply flexibility, the greater the impact curtailments exert on LMP.

Supply curves were estimated for the ISO-NE market for three distinct periods to account for seasonal differences in market fundamentals. The first period is comprised of the fall and spring months of the Reporting Period, the months of September, October, November 2004 and March, April, and May 2005. The second is the winter period that includes the months of December 2004 and January and February 2005. The last is the summer period of June, July, and August of 2005. Figure 3-1 through Figure 3-6 depict the LMPs observed during each of these time periods for both the Day-Ahead and Real-Time markets.

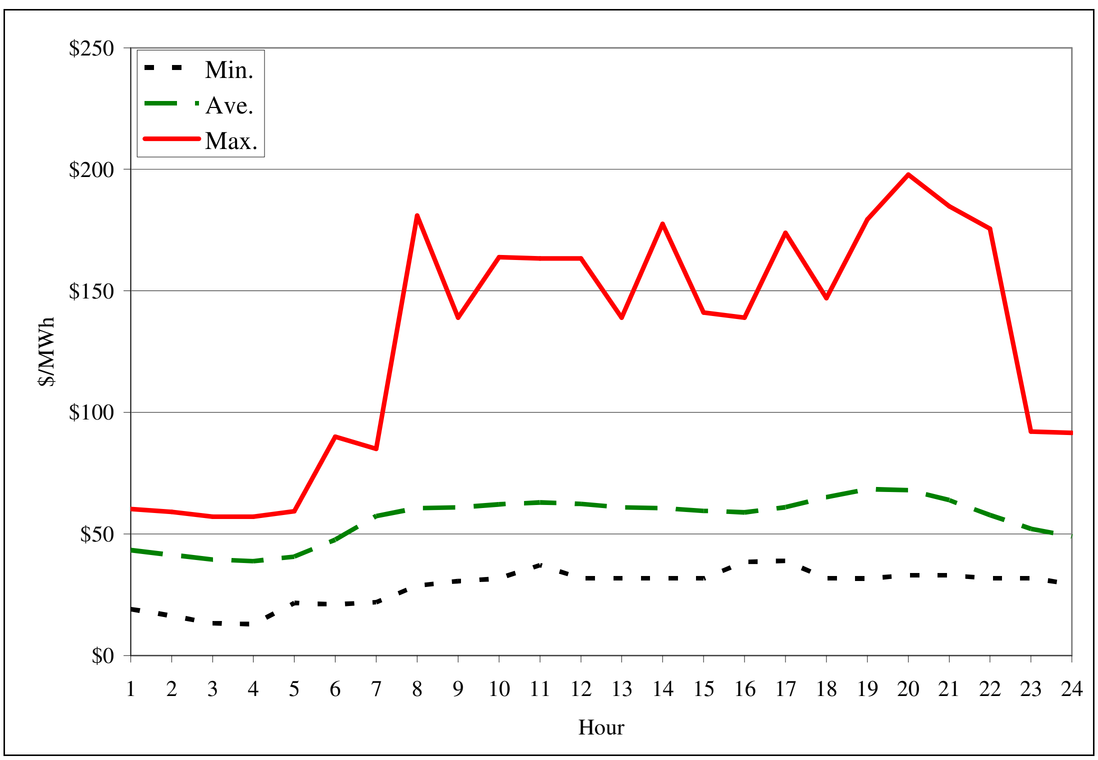

Figure 3-1: ISO-NE Day-Ahead Market LMP Statistics Spring 2004 & Fall 2005

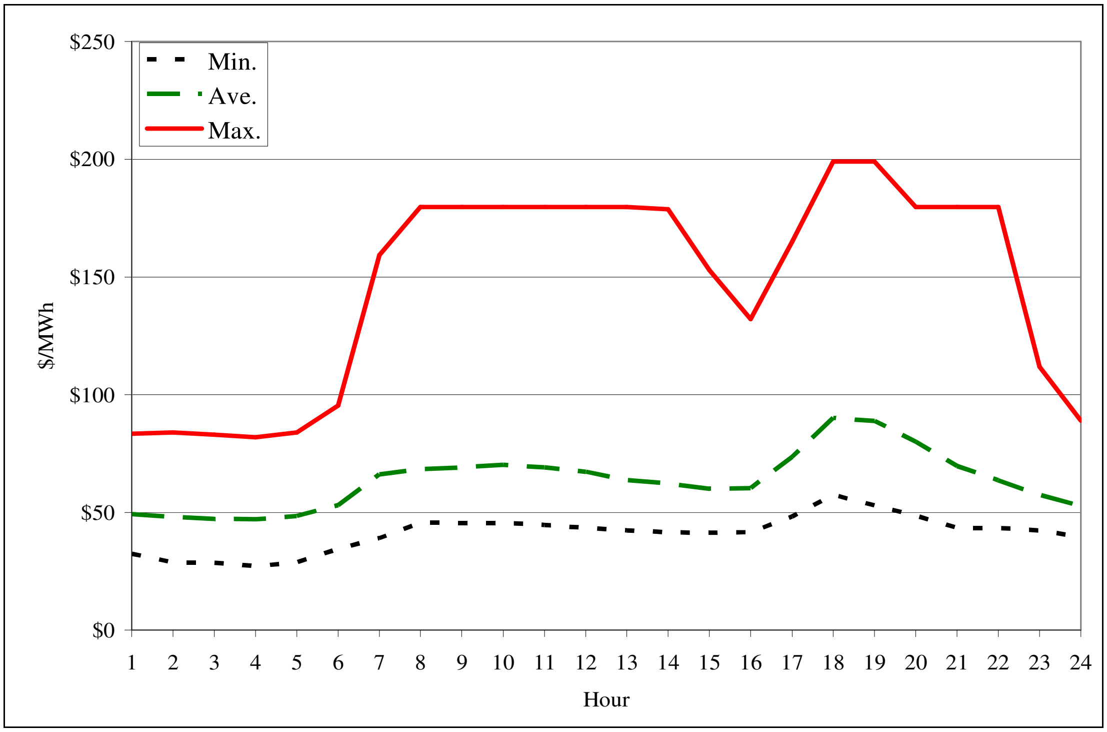

Figure 3-2: ISO-NE Day-Ahead Market LMP Statistics Winter 2004/2005

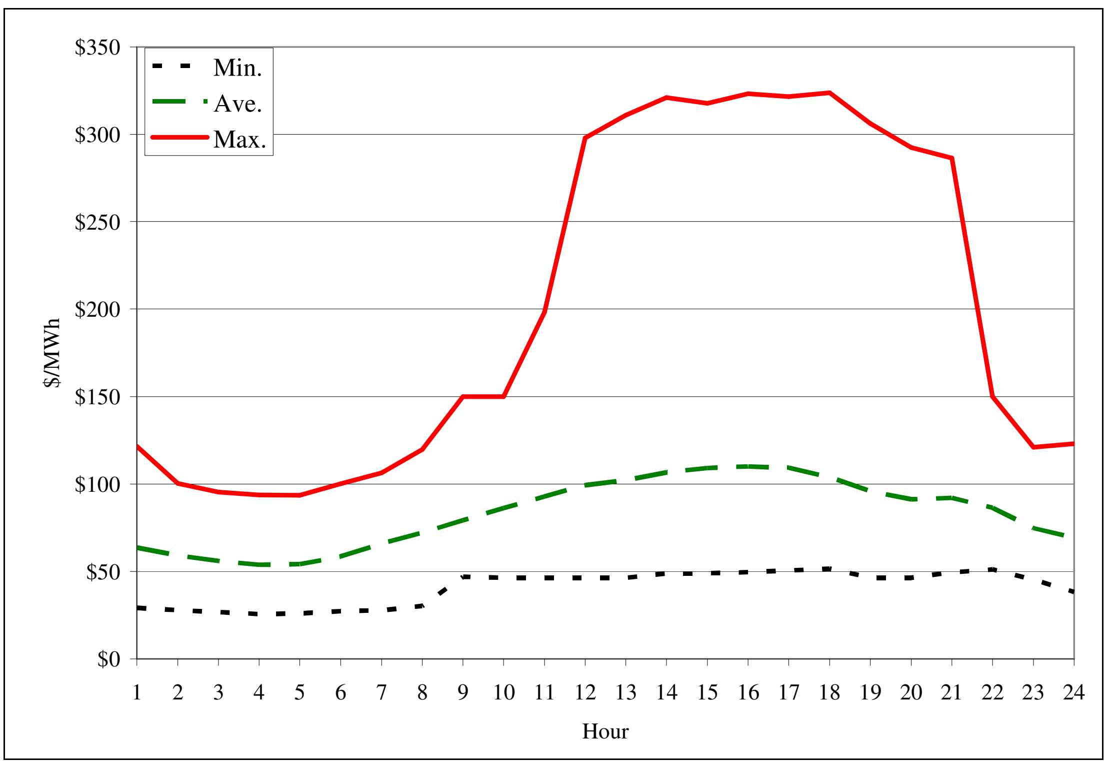

Figure 3-3: ISO-NE Day-Ahead Market LMP Statistics Summer 2005

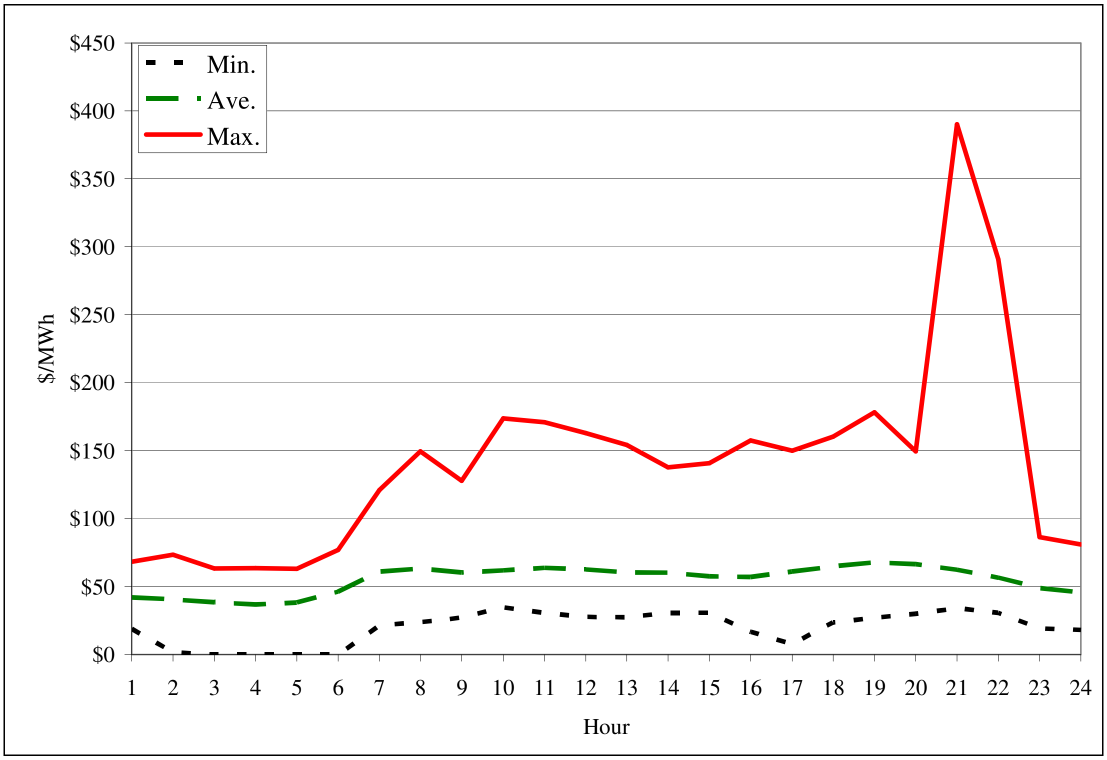

Figure 3-4: ISO-NE Real-Time Market LMP Statistics Fall 2004 & Spring 2005

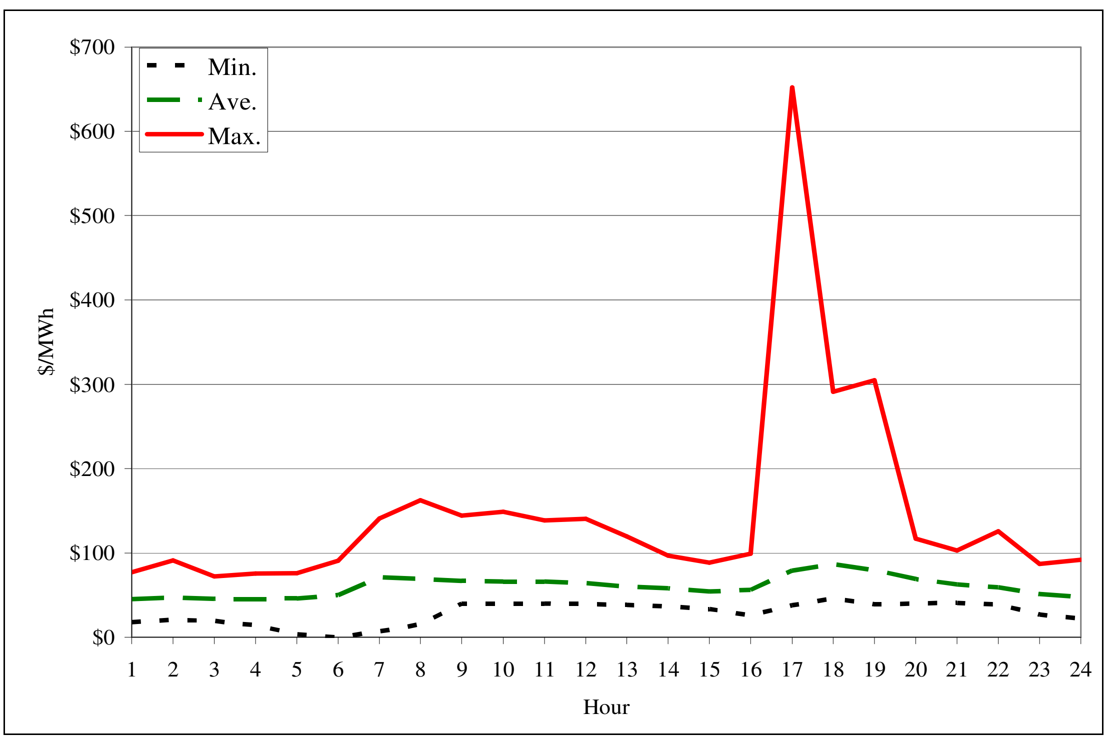

Figure 3-5: ISO-NE Real-Time Market LMP Statistics Winter 2004/2005

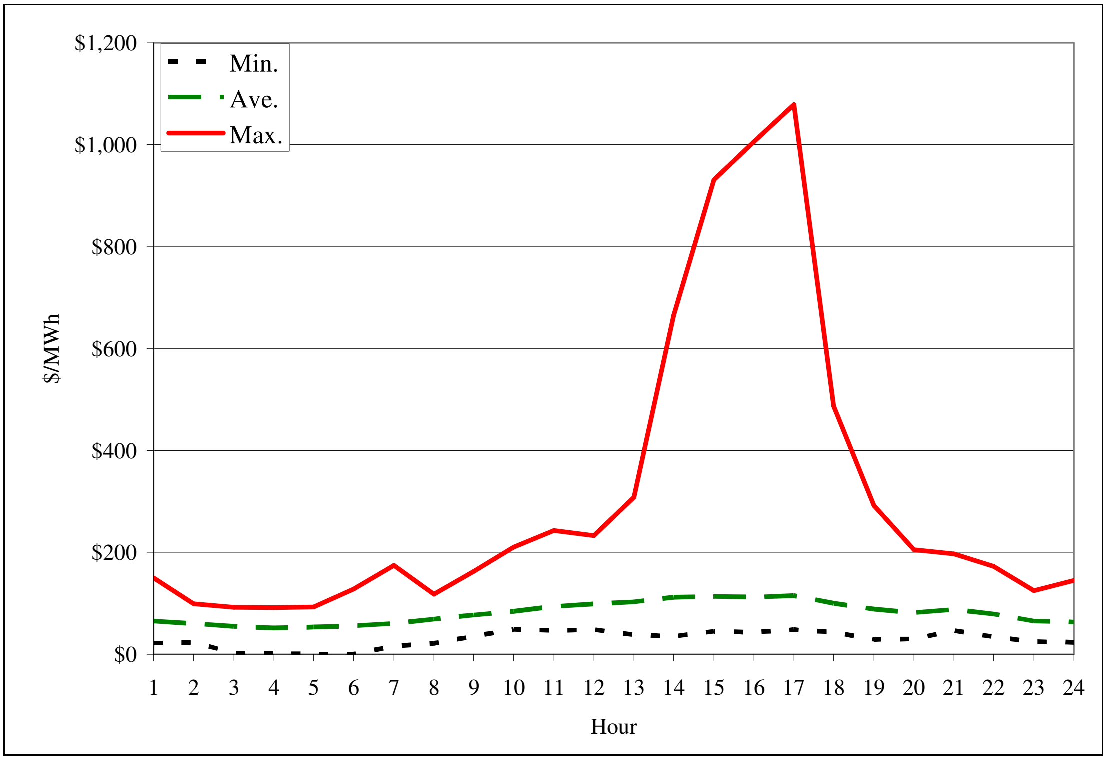

Figure 3-6: ISO-NE Real-Time Market LMP Statistics Summer 2005

The LMP curves differ substantially by season and market. The winter period (Figure 3-2 and Figure 3-5) shows a pronounced spike in the maximum price and an increase in the average during the later afternoon hours, in contrast to summer and Fall/Spring where the peak occurs in the middle of the afternoon. The difference between maximum prices in the overnight and daylight hours are relatively small in the Day-Ahead Market, reaching $250/MWh in the Winter, but are sizable in the Real-Time Market in every season, in excess of $350/MWh up to $1,000/MWh.[14]

As described earlier, the supply flexibility measures the slope of the market supply (generator bid) curve. Table 3-1 provides some basic statistics of the estimated supply

[14] ISO-NE's markets utilize programming models to produce unit commitment and dispatch instructions as well as set market-clearing prices for electricity. Given the nature of such models, it is possible for markets to clear at prices in excess of the market bid cap of $1,000/MWh.

price flexibilities for the three periods and the two ISO-NE electricity markets analyzed.[15] As the table indicates, supply flexibilities are very different across the two markets, with the Real-Time market estimates showing roughly a five-fold increase over the price flexibilities observed in the Day-Ahead market. This effect, however, varies considerably from zone to zone, with Maine (ME) showing the largest difference between markets, in excess of a factor of nine, while Connecticut (CT) maintains less than a 33% increase from Day-Ahead to Real-Time. The market is usually in the flat part of the supply curves, regardless of zone or season, as evidenced by the very low average price flexibilities. However, there are times when the market enters the steeper part of the supply curve, so much so that during the summer of 2005 in NEMA, a 1% reduction in demand would have resulted in a 15% reduction in price. Overall, Connecticut and NEMA exhibit the highest average and maximum estimated price flexibilities, followed by Rest of New England (RONE) and finally ME.

			Supply Price Flexibility		
Season	**Market**	**Zone**	**Min.**	**Ave.**	**Max.**
Fall/Spr	DA	ME	-0.4	0.1	0.4
		NEMA	-0.8	0.5	1.9
		CT	0.2	0.9	3.6
		RONE	-1.0	0.3	1.5
	RT	ME	0.2	1.5	5.4
		NEMA	-0.1	1.7	7.9
		CT	0.0	1.3	4.6
		RONE	0.0	1.0	4.4
Winter	DA	ME	-0.3	0.2	1.6
		NEMA	0.5	1.3	3.1
		CT	0.4	1.7	7.9
		RONE	-0.6	0.7	3.9
	RT	ME	0.5	1.9	9.7
		NEMA	0.3	2.0	8.4
		CT	0.3	1.7	12.4
		RONE	0.3	2.0	13.0
Summer	DA	ME	-0.5	0.1	0.3
		NEMA	-0.2	0.3	1.8
		CT	0.2	0.8	2.4
		RONE	-0.1	0.4	0.9
	RT	ME	-0.1	0.9	2.5
		NEMA	-0.4	1.2	15.3
		CT	0.2	1.3	6.4
		RONE	0.2	1.2	4.5

Table 3-1: Supply Price Flexibility Estimates by Season, Market and Zone

3.2 Real-Time Price Response Program Benefits

Table 3-2 contains zonal estimates of the price effects and associated benefits from Real-Time Price Response Program performance.[16] Overall, the Real-Time Price Response Program produced benefits ($9,278,185) that exceeded its costs ($5,156,534) by 80%. The load curtailments undertaken during declared events reduced the Real-Time market

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[15] Due to characteristics of the bulk power system, the eight current ISO-NE Load Zones can be aggregated up to produce four distinct zones or superzones: Maine (ME), NEMA, Connecticut (CT), and the Rest of New England (RONE).

[16] The payment and performance statistics in this filing for all programs are subject to change based on resettlement data. Data from June through September 2005 may be revised based on the 90-day resettlement.

LMP by an average of 97 cents per MWh. The largest average price reduction occurred in NEMA ($1.95/MWh) while the smallest was in the Rest of New England area, which experienced an average price reduction of 28 cents per MWh.

Those retailers purchasing energy in the Real-Time market paid less for their electricity when these program participants reduced load.[17] The estimated savings is directly tied to the level and frequency of the price reduction in the simulated areas, thereby resulting in the largest savings in NEMA of $1,010,490, while Maine produced only $127,291 (Table 3-2). If Real-Time Energy Market prices are consistently lower due to Real-Time Price-Response Program load curtailments, then commodity suppliers seeking to purchase

				Transfer Benefits			
Zone	Performance (MWh)	Program Payments ($)	Average RT LMP ($/MWh)	Average Price Reduction ($/MWh)	Market Bill Savings ($)	Hedge Contract Savings ($)	Benefits to Payment Ratio
Maine	5,518	$578,617	$75.44	$0.91	$127,291	$651,600	1.35
NEMA	18,555	$2,169,036	$86.65	$1.95	$1,010,490	$4,504,929	2.54
CT	10,908	$1,296,868	$91.87	$0.50	$278,107	$1,310,070	1.22
Rest of ISO-NE	10,455	$1,112,012	$81.83	$0.28	$229,146	$1,166,551	1.26
	45,436	$5,156,534	$84.47	$0.97	$1,645,034	$7,633,151	1.80

Table 3-2: Estimated Real-Time Price Response Program Benefits by Zone

hedge contracts in the near future will demand lower rates.[18] A proxy for lower hedge contract prices would be the reduction in average LMP during the hours for which hedge contracts are generally written (i.e. weekdays between 6 a.m. and 10 p.m.).[19] Using this proxy, those buying long-term supply contracts would save $651,000 in Maine, but would save over $4.5 million in NEMA (Table 3-2).

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[17] Based on an evaluation of ISO-NE market settlement data, roughly 11% of load is purchased in the Real-Time Market.

[18] Based on an evaluation of ISO-NE market settlement data, roughly 60% of load is purchased in the bilateral market.

[19] Long-term contract rates are based on a combination of the expected price as well as a risk premium for accepting the fact that the future is not known with certainty. This calculation of hedge savings herein only takes into account changes in the expected electricity price, not any associated reduction in price volatility resulting from these Demand Response resources. Thus, the estimate of the hedge market savings in the tables should be considered a lower bound.

Economists consider these bill savings to be transfer payments, money that moves away from one party (i.e. electricity producers) to another (i.e. commodity providers), and are subjectively called benefits only from the perspective of those receiving such monies. A more comprehensive metric for quantifying the relative success of the Real-Time Price Response Program is to fully incorporate how all parties are affected by these load curtailments, thereby producing an estimate of the change in social welfare. However, estimating these social welfare effects are only warranted if an alternative to ISO-NE's Real-Time Price Response Program is available that produces the same, or at least a comparable, outcome. With the absence of pervasive time-varying retail rates (e.g. Real-Time Pricing or "RTP") in New England, ISO-NE has become the *de facto* agent responsible for inducing demand response regardless of the welfare implications. At such time when RTP or similar time-varying retail rates become widespread in New England, a comparison of the welfare implications associated with these two options is warranted, the results of which can be used by policy-makers to evaluate alternative approaches to achieving price responsive demand.

3.3 Day-Ahead Load Response Program

Starting in the early summer of 2005, ISO-NE implemented its Day-Ahead Load Response Program (DALRP), which allows demand response resources to offer their load curtailments into the Day-Ahead Energy Market (DAM). As mentioned above, if such offers were below the zonal market-clearing price (LMP), then the load curtailment is scheduled and the asset is expected to provide the reduction in Real-Time. These bids would not directly affect the DAM LMP, as they are evaluated after the Day-Ahead Energy Market clears. However, it was expected that once the program grew to a sufficient size, those entities selling load into the Day-Ahead market would incorporate these "after-market bids" into their bidding strategy to anticipate lower levels of demand in Real-Time. Any additional performance provided by these resources, above and beyond that which was scheduled Day-Ahead, is paid the Real-Time LMP, and therefore would affect only the Real-Time Energy Market.[20]

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[20] ISO-NE rules preclude joint participation in the Real-Time Demand Response Program and the Real-Time Price Response Program. Thus, end-use customers wishing to provide their curtailment or generation capability as both an emergency/reliability and a price-responsive resource must enroll into the Real-Time Demand Response Program and the Day-Ahead Load Response Program.

During the Reporting Period, there was only a single asset enrolled in DALRP, whose offers were unlikely to move the market at a level sufficient enough for purchasers of electricity in the Day-Ahead market to adjust their bid strategy.[21] In order to provide a comprehensive analysis of the effects this one asset had during the Reporting Period, two alternative approaches were undertaken. First, it was assumed that the full consequences of the scheduled load curtailments and any additional performance would only be felt in the Real-Time market, as the program enrollment and performance is currently too small to warrant much attention from those purchasing the electric commodity. Second, to provide an estimate of what effects might have been experienced if even this one asset's offers were integrated by those bidding into the Day-Ahead market, a second set of results were produced assuming the scheduled load curtailment could affect the Day-Ahead market, with any additional performance only reducing the Real-Time market LMP.

As illustrated in Table 3-3, a total of 23 MWhs were scheduled in the Day-Ahead market, but an additional 367 MWhs were provided in Real-Time above and beyond those scheduled, resulting in total performance payments of $42,880. Because DALRP offers are evaluated after the Day-Ahead Market clears and can not directly affect the Day-Ahead Market LMP, estimates of benefits were derived by assuming that all load curtailments associated with DALRP affect the Real-Time market only. Thus, the estimates of transfer benefits incorporate only price changes that occur in Real-Time. Those purchasing load in the spot market during these DALRP load curtailments would have saved $10,583, while those undertaking hedge contracts in the future could expect to see a $46,166 reduction in the cost of such contracts. The second row of the table – i.e., Integrated method –assumes that the 23 MWh of load scheduled Day-Ahead would have affected the Day-Ahead market, while the remaining 367 MWhs reduced LMPs in the Real-Time market, producing bill savings to those purchasing load in these two ISO-NE electricity markets totaling $11,324.[22] If such price reductions continue in the future,

[21] At the time of this writing, no assets are presently active in the DALRP.

[22] Based on an evaluation of ISO-NE market settlement data, roughly 29% of load is purchased in the Day-Ahead Market.

then those in the hedge market would expect to see a savings of $47,377. Combined, these benefits exceed program payments by a margin of 37%.

				DALRP MWhs Affecting		Transfer Benefits		
Method	Scheduled Offers (MWh)	Additional Performance (MWh)	Total Payments ($)	Day-Ahead Market (MWh)	Real-Time Market (MWh)	Market Bill Savings ($)	Hedge Contract Savings ($)	Benefits to Payment Ratio
Sequential	23	367	$42,880	0	390	$10,583	$46,166	1.32
Integrated	23	367	$42,880	23	367	$11,324	$47,377	1.37

Table 3-3: Estimated Day-Ahead Load Response Program Benefits by Zone

3.4 Demand Response Program Benefits

ISO-NE's demand response program is activated only during extreme emergency operations when the ISO-NE's OP-4 condition has been declared. Thus, this program's resources contribute to the reliable operation of the bulk power system by reducing the overall load that must be served during emergency conditions. Under the most extreme circumstances, such as those experienced during the 2003 Northeast Blackout, energized program participants who reduce consumption allow others not yet connected to the grid the ability to be brought online faster. During less severe system conditions, program induced load curtailments reduce the probability that a system disruption will lead to a service interruption.

During the summer of 2005, demand growth combined with weather conditions resulted in New England reaching an all-time record system peak. System conditions on July 27th necessitated the activation of Demand Resources in Connecticut, resulting in 1,100 MWh of load reduction and energy payments of $552,930. Since these resources improve reliability, program benefits are calculated based on the Value of Expected Un-served Energy (VEUE).

(1) VEUE = Value of Lost Load (VoLL) * Δ LOLP * Load @ Risk

To calculate this, it is necessary to have estimates for the three component pieces. A range of value was used to represent the incremental cost of an outage on end-use

Change in LOLP	Outage Cost			
	$2,500/MWh	$5,000/MWh	$7,500/MWh	$10,000/MWh
0.05	$291,131	$582,263	$873,394	$1,164,525
0.10	$582,263	$1,164,525	$1,746,788	$2,329,050
0.15	$873,394	$1,746,788	$2,620,181	$3,493,575
0.20	$1,164,525	$2,329,050	$3,493,575	$4,658,100

Table 3-4: Estimated Demand Response Program Reliability Benefits (5% Load at Risk)

customers.[23] To estimate how these load reductions improved reliability, a simplified approach[24] was used that assumed several different values for the reduction in the Loss of Load Probability (LOLP) to produce a range of benefit estimates. Finally, it was assumed that roughly 5% of CT zonal load was at risk of an outage, a conservative estimate by most standards.

The reliability benefits the Demand Response program provided to electricity consumers in the state of Connecticut are shown in Table 3-4. As noted above, it was assumed that 5% of Connecticut load was at risk of an outage during the event. If the program-induced load reductions improved the LOLP by 0.10 or greater, then the reliability benefits would have exceeded costs. Alternatively, if the outage cost (i.e., VoLL) were $5,000/MWh or higher, then the value of increased reliability would have offset the payments to program participants under all LOLP scenarios.

[23] Over the past two decades, there have only been a handful of meaningful and reliable attempts to quantify the cost incurred by customers whose electricity service is interrupted. The research indicates the value varies dramatically from industry to industry, and varies with the length of notice of the outage, and with the duration of the interruption itself. The lowest Value of Lost Load used herein ($2,500/MWh) represents a rather conservative estimate, given the publicly available information. The bulk of the research surrounding the 2003 Northeast Blackout indicates outage costs were in excess of $7,000/MWh.

[24] A more rigorous analysis would involve stochastic simulations of the transmission grid in Connecticut for a range of different system contingencies that could have occurred during the hours of the event, given system conditions at the time. Such an analysis was beyond the scope of this work.

4 Process Evaluation

4.1 Introduction

The process evaluation of the 2005 ISO-NE demand response programs focused primarily on the level of stakeholder satisfaction with the programs and with the processes used to improve the programs. A focused process survey was conducted by e-mail that evaluated the level of satisfaction with the current program offerings and the responsiveness of ISO-NE staff to stakeholder recommendations. The survey also contained open-ended questions to identify any additional issues that should be addressed.

Additionally, there was a brief customer survey that was conducted with program participants and retirees that primarily investigated customer satisfaction with the 2005 ISO-NE demand response program offerings. The customer survey also collected customer demographic information and probed for customer reported preferences for the Day-Ahead Option.

4.2 Evaluation Overview

A key aspect of this study utilized existing data resources at ISO-NE to gain an understanding of the operations of the demand response programs. ISO-NE program documentation was gathered and reviewed in the early stages of the study. This information was then used to frame the stakeholder and customer surveys. Responses to the surveys were the primary source of data for the process evaluation.

Both of the surveys were implemented via e-mail and were Internet-based. Although the surveys were brief (between 12 -18 questions), the respondents were able to leave the survey at any time and then come back to the survey and start at the last completed question. In addition, the survey included several open-ended questions allowing the respondent to be creative in their responses.

4.3 Stakeholder Survey

The Stakeholder surveys were distributed to a total of 28 individuals from various stakeholder groups. The interviewee groups represent five distinct stakeholder groups, as follows:

- Local distribution companies,
- Demand response providers,
- Competitive retail electricity providers,
- Metering and Internet-based communication system providers, and
- State regulators.

The survey was first implemented over a four-week period using an e-mail invitation and two follow-up e-mail reminders. After the initial implementation, a series of phone calls were made to the 21 recipients that did not respond to the initial e-mail distribution and additional e-mail survey invitations were sent out. Finally, after the two-week phone solicitation period, an additional e-mail survey was sent out. Table 4-1 provides a summary of the survey distribution and response rate by stakeholder group type, which shows that the overall response rate was 75%. In general the level of response was fairly representative of the stakeholders that are active in the ISO-NE demand response programs.

Stakeholder Group Type	Surveys Sent	Surveys Complete	% Complete
Local Distribution Company	13	9	69%
Demand Response Provider	2	1	50%
State Regulators	5	4	80%
Competitive Electricity Provider	4	3	75%
Metering & IBCS Provider	4	4	100%
Totals	**28**	**21**	**75%**

Table 4-1: Stakeholder Survey Responses

The survey was structured so that the respondent first provided their level of familiarity with a particular process or program, and then was asked to provide their level of satisfaction with the process or program. After each question related to the respondent's level of satisfaction with a process or program, respondents were asked to provide any comments or suggestions on how to improve the process or program.

The following discussion of survey results are organized by business processes related to the delivery of the demand response programs. The results have been divided into two general categories: program implementation mechanisms and program delivery processes. The program implementation mechanisms include the day-to-day mechanics of the programs such as the customer enrollment process, the event notification process, the meter data submission process, and the settlement process. The program delivery processes include the program marketing materials, ISO-NE marketing support, and the Demand Response Working Group (DRWG) meetings. Additionally, the stakeholders were asked about the Day-Ahead Option and whether they intend to enroll any of their resources into the Day-Ahead Option.

4.3.1 Program Implementation Mechanism

The program implementation portion of the stakeholders' survey included familiarity and satisfaction questions about the customer enrollment process, event notification process, metered data submission process and settlement process. The familiarity questions were on a 1 to 3 scale (1 being "Very Familiar" and 3 being "Not at All Familiar") and satisfaction questions were on a 1 to 5 scale (1 being "Very Satisfied" and 5 being "Not at All Satisfied"). Table 4-2 provides a summary of the results of the program implementation questions, which shows that all of the business processes received a positive satisfaction rating (less than 3.0). The settlement process received the lowest rating of 2.67 and the enrollment process was slightly better at 2.65.

	Familarity		Satisfaction	
Topic	N	Rating	N	Rating
Enrollment Process	21	1.9	17	2.65
CAMS Application	20	2.6	5	2.60
Notification Process	21	1.7	16	2.19
Meter Data Submission Process	21	2.0	16	2.44
Settlement Process	21	2.0	15	2.67

Table 4-2: Results of Program Implementation Survey Questions

In general, when a respondent indicated that they were not at all familiar with a process, they did not provide a satisfaction rating as evidenced by the decrease in the response rate between the familiarity and satisfaction questions. Note that respondents indicated that they were least familiar with the Customer and Asset Management System (CAMS) application (2.6 out of 3.0) and only five of the respondents provided a satisfaction rating, the average score of which was also 2.6. The CAMS application is the current platform used by Enrolling Participants to manage their assets in the demand response programs, including enrollment, program changes, and other resource attributes. Of all the business processes with which the respondents were most familiar and satisfied was the notification process, which had familiarity rating of 1.7 and a satisfaction rating of 2.19.

There were several stakeholder comments and recommendations for changes and improvements to the enrollment process and the CAMS application. A common theme was that stakeholders would benefit from additional training on the use of the CAMS application. One respondent suggested an annual refresher session.

4.3.2 Program Delivery Processes

The program delivery portion of the stakeholder survey also included familiarity and satisfaction questions about the program marketing materials, ISO-NE marketing support, and the DRWG meetings. The stakeholders were also asked to provide their level of satisfaction with the responsiveness of ISO-NE's Demand Response Department. Once again, the 1 to 3 scale was used to measure familiarity and the 1 to 5 scale was used to measure satisfaction with 1 being the best rating and 3 or 5 being the worst depending on the type of question. Table 4-3 provides the results of the program delivery survey questions, which shows that once again the level of satisfaction was quite good with all of the ratings being positive (less than 3.0). The best ratings were given for the responsiveness of the Demand Response Department (1.76) and the marketing support (1.94), which were both very good. The marketing materials received the lowest rating in this group of 2.41, but this rating is still quite positive.

	Familarity		Satisfaction	
Topic	N	Rating	N	Rating
Marketing Support	21	1.9	15	1.94
DR Marketing Materials	21	1.8	17	2.41
DR Working Group Meetings	21	1.6	16	2.31
Responsive of DR Department			21	1.76

Table 4-3: Results of Program Delivery Survey Questions

In general, the comments were all quite positive for the program delivery processes with ISO-NE Demand Response Department receiving praise for being "very customer focused" and "always available to support anyone who requests their help in explaining the ISO programs or processes." There were some comments that suggested that marketing materials and customer tools might need to be updated to reflect a recent change in energy prices. In addition some state regulators wanted to know how to obtain copies of the material.

Finally, stakeholders were asked about their level of familiarity with the Day-Ahead Option and whether they were planning to enroll any of their resources in the Day-Ahead Option. This question was only relevant to 12 of the 21 respondents because they were Enrolling Participants or Demand Response Providers. On average they indicated that they were somewhat familiar with the Day-Ahead Option (2.0 on the 1 to 3 scale). Four of the twelve respondents indicated that they would consider enrolling resources and the remaining two thirds indicated that they would not. The primary reasons cited for not enrolling resources was a lack of program understanding, the complexity of the program and the fact that customers have not expressed interest. Interestingly, only two respondents indicated that they were very familiar (1.0 on a scale from 1 to 3) with the Day-Ahead Option and both of them indicated that they would consider enrolling resources. This would seem to indicate that more education is necessary in order to convince stakeholders to promote the Day-Ahead Option.

4.4 Customer Satisfaction and Characterization

Customer surveys were designed and administered in mid-September and early October 2005 to measure program participants' satisfaction with the program and its key features, to characterize the population of program participants, and to identify customers' demand response capabilities.

There were two distinct surveys developed: one for customers that participated in the Price Program and one for customers that participated in the Reliability Programs. A total of 673 surveys were distributed using a web-based survey tool. A total of 122 customers completed the survey.

Table 4-4 provides a breakdown of the number of surveys that were sent to each group, the number of completions, and the response rate for each.[25] The Reliability Program participants' response rate was the highest at 29%, while the Price Program participants' response rate was 13%. The overall average response rate of 18% is comparable with that of last year's survey. It is important to note that although the survey completion rate decreased this year particularly for the Reliability Programs, more surveys were sent out and the actual number of complete surveys increased by about 39% - from 88 completes in 2004 to 122 completes in 2005.

Program	Net Surveys Sent	Complete	Complete Ratio	2004 Complete Ratio
Reliability	224	64	29%	42%
Price	449	58	13%	16%
Total	673	122	18%	21%

Table 4-4: Survey Frame and Response Rates

[25] The survey was distributed by e-mail and follow-up e-mail reminders were sent out during the administration period. Customers were provided a link to the survey, which was completed on-line. The customers had the ability to leave the survey at any point and come back where they left off.

4.4.1 Survey Frame and Response

The distribution of responses by load zone are displayed in Figure 4-1, which shows that the Connecticut (CT) Load Zone had the highest number of survey respondents with a total of 66 or 54% of the total. This result is not unexpected since the majority of the customers participating in the Reliability Programs are located in the CT Load Zone: 313 surveys were sent to customers in the CT Load Zone, or 41% of the total. In general, the responses across programs and zones were fairly representative of the number of surveys that were sent out and of the distribution of program participants among Load Zones.

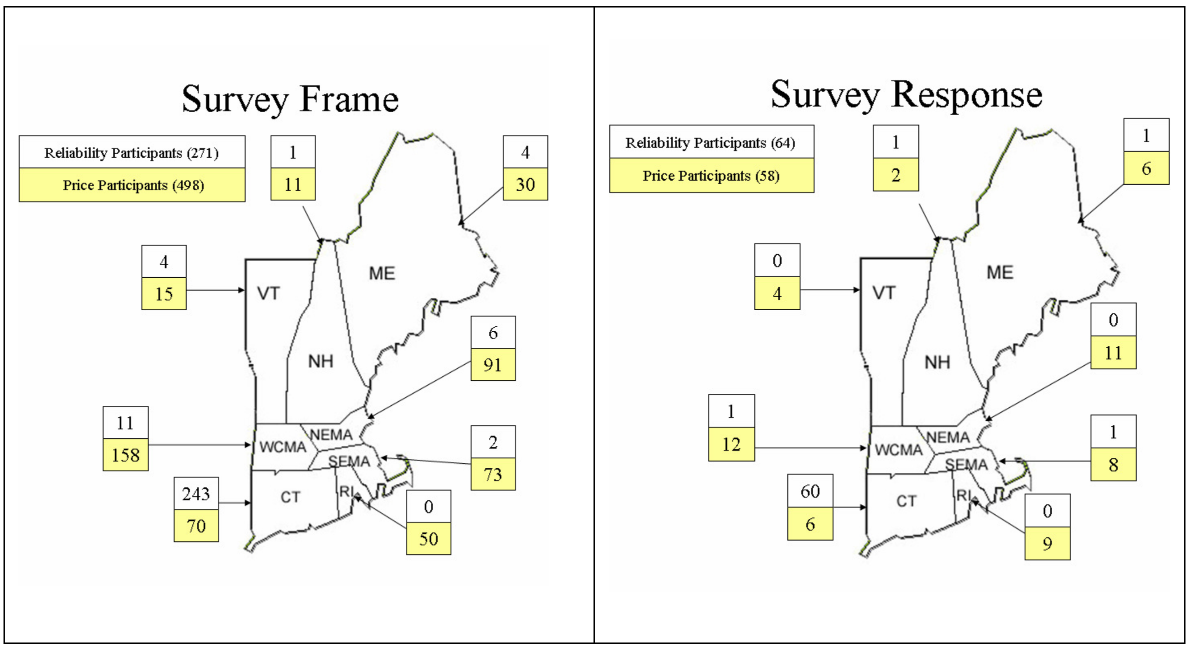


Figure 4-1: Survey Sample Frame and Responses by Zone

The survey responses provide insight into how participating customers value demand response program participation. The survey results are useful for improving program marketing and administration, and for evaluating program modifications and refinements to make participation more attractive and effective.

4.4.2 Overall Program Satisfaction

As illustrated in Figure 4-2, participants in the Reliability and Price Programs reported that overall they were quite satisfied, providing ratings of 1.8 and 2.1, respectively. These ratings have improved from those provided by last year's respondents, particularly among Reliability Program participants.

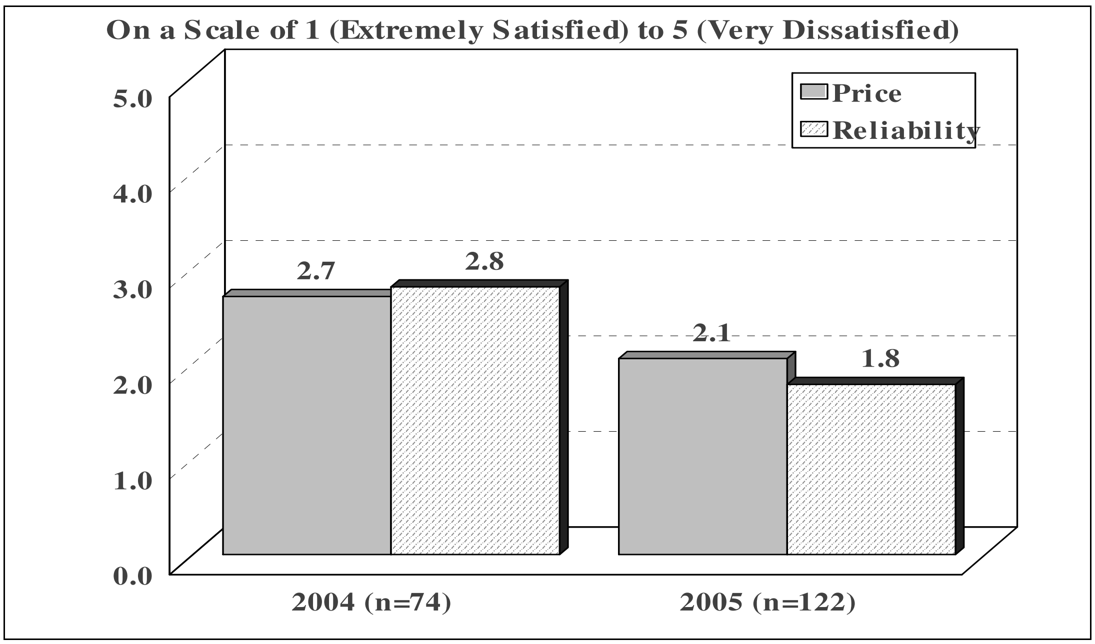


Figure 4-2: Overall Program Satisfaction

Satisfaction scores were also provided for the notification process and the speed of payments as shown in Figure 4-3. Once again the satisfaction levels were fairly good with the notification process receiving scores of 1.9 and 2.2 and the speed of payment receiving slightly lower ratings of 2.4 and 2.7 from the price and reliability respondents, respectively. The payment speed is a direct function of how quickly and frequently Enrolling Participants provide ISO-NE with accurate meter readings within the time constraints of the normal monthly settlement schedule. In both instances the scores improved over the survey responses for the same questions in last years' survey.

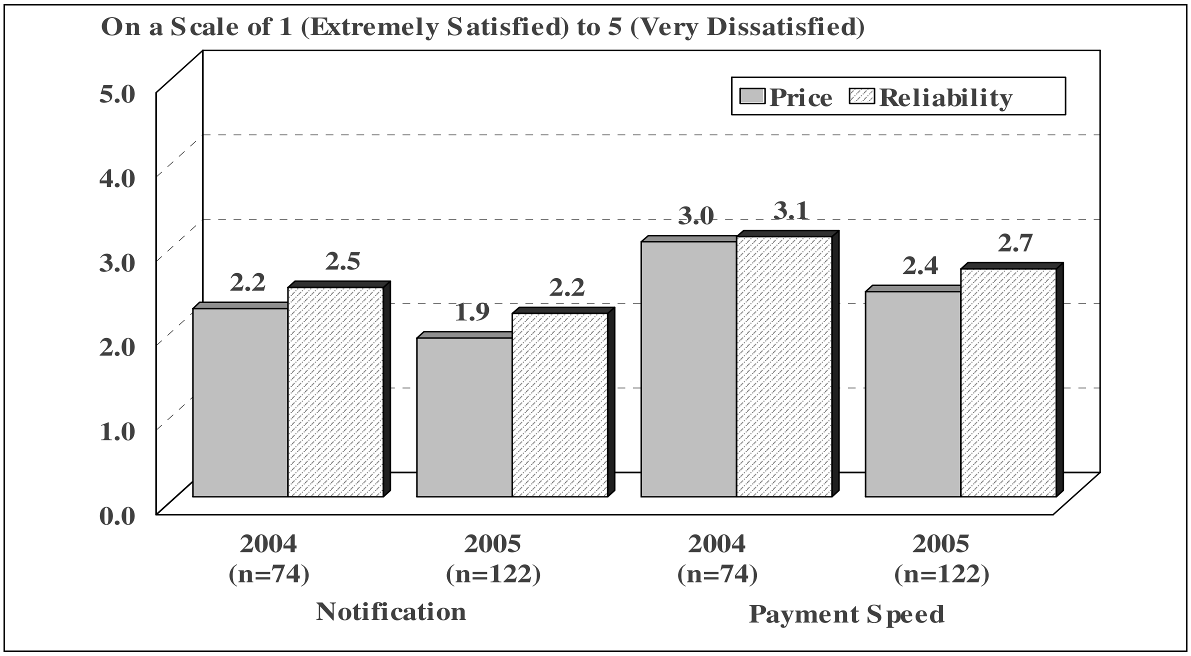
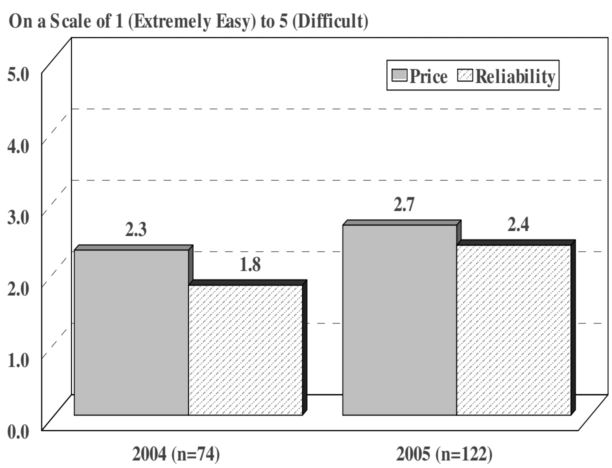


Figure 4-3: Satisfaction with Payment and Notification

Figure 4-4 provides the results for the questions about the ease of understanding of marketing materials, and the overall customer friendliness of the program. In this case the scores for the ease of understanding of the marketing materials, although quite good (2.7 and 2.4 for the price and reliability respondents respectively), were actually lower than in 2004. This decrease is probably due to the increased marketing activities by Enrolling Participants and Demand Response Providers in Southwest Connecticut (SWCT) under the SWCT Gap RFP, as well as the introduction of the new Day-Ahead Option. The overall customer friendliness of the program was rated at 2.1 and 1.8 for the Price and Reliability Programs respectively, which was also an improvement over the 2004 ratings.

Understanding of Program Marketing Materials



Customer Friendliness of Program

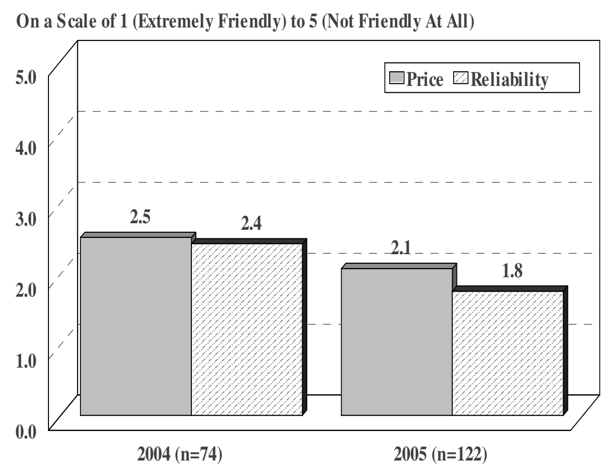


Figure 4-4: Measurements of Demand Response Program Accessibility

In summary, the customer ratings for all of the program satisfaction questions were very good. With the exception of the ease of understanding the marketing materials, all of the customer ratings increased from last year's evaluation. Consistent with past survey results, customers' satisfaction with the speed of payment had the lowest rating of 2.4 and 2.7 from the price and reliability customers, respectively. The two key overall program ratings for satisfaction and customer friendliness were both rated at 2.1 and 1.8 by the price and reliability customers, respectively.

4.4.3 Participant Characterization

The amount of time respondents spend buying and managing energy would seem to be a good indicator of participation in a program. The maintained hypothesis was that those companies that spend more time managing energy are more likely to participate. Because they better understand the facility's load management capability, they should be more attuned to opportunities to save money by participating in demand response programs.

As Figure 4-5 illustrates, however, this is not necessarily the case. In fact, the percentage of respondents who reported spending more than 10% of their time managing energy has decreased over the past year, particularly among Reliability Program participants. This suggests that participants may be using the program as a means of lowering their energy costs without making a large time commitment. Another potential explanation is that program participation has expanded beyond the "early adopters," – that is, while the program initially appealed to those customers that devote a significant amount of time to energy issues, the program may now be capturing more "mainstream" customers who spend less time on energy issues.

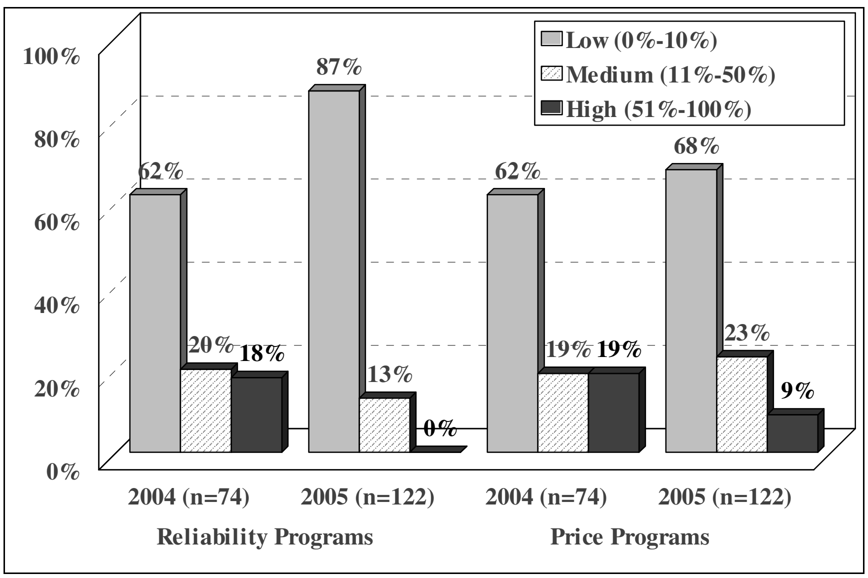


Figure 4-5: Time Spent Managing Energy

Respondents were also asked to indicate how their company purchases the energy supply portion of their electricity (Figure 4-6). Most respondents purchase electricity on a fixed or flat rate. The majority of reliability participants purchase electricity on a fixed rate through their local utility (about 88%), while price participants purchase electricity through competitive suppliers (about 52%). This difference is due to the location of the customers. The majority of the reliability customers are located in Connecticut where low standard offer rates for energy have retarded the migration of customers from the utilities to competitive energy suppliers. In contrast, the majority of the price response program customers are located in Massachusetts, which has had a much higher migration rate of customers from utility standard offer or default service to competitive energy suppliers. The "other" responses were mostly mixes of the other two responses.

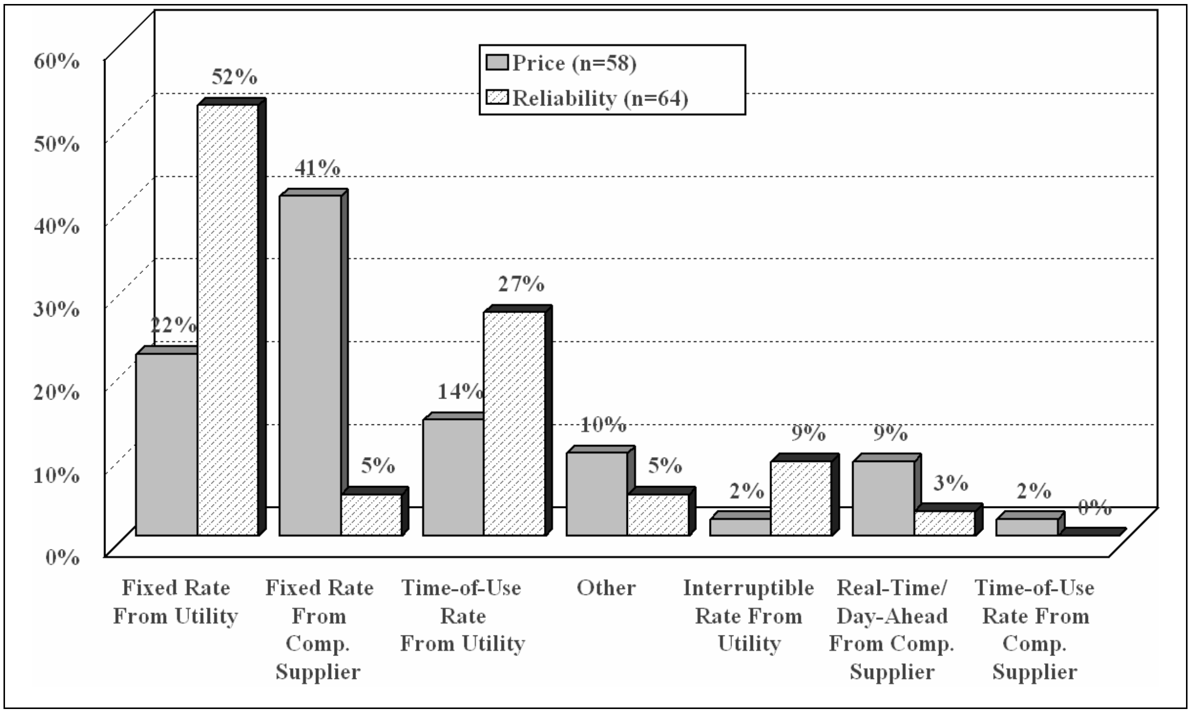


Figure 4-6: Electricity Supply Purchases

Figure 4-7 presents the results of the electricity supply question in a slightly different way, which focuses on the type of rate that the respondent purchases electricity – either a fixed or some type of time-variant rate. In this case, there is very little difference between price and reliability customers, with about 60% of the total customers reporting that they are purchasing electricity on a fixed rate. Reliability customers are more likely than price customers to be on either a Time of Use rate or an interruptible rate. The overall use of Dynamic Pricing (i.e. rates more closely tied or indexed to hourly Real-Time or Day-Ahead wholesale prices) is about 6%, but price customers are more likely to be on an hourly rate than reliability customers. The significance of this statistic is that despite rising energy costs, increasing peak load, and a degrading load factor in the region, very few retail customers in the region are on Dynamic Pricing. Customers selecting Dynamic Pricing would be in a position to manage their energy costs, which, collectively, would mitigate peak load and improve the overall load factor and productivity of New England's electricity system.

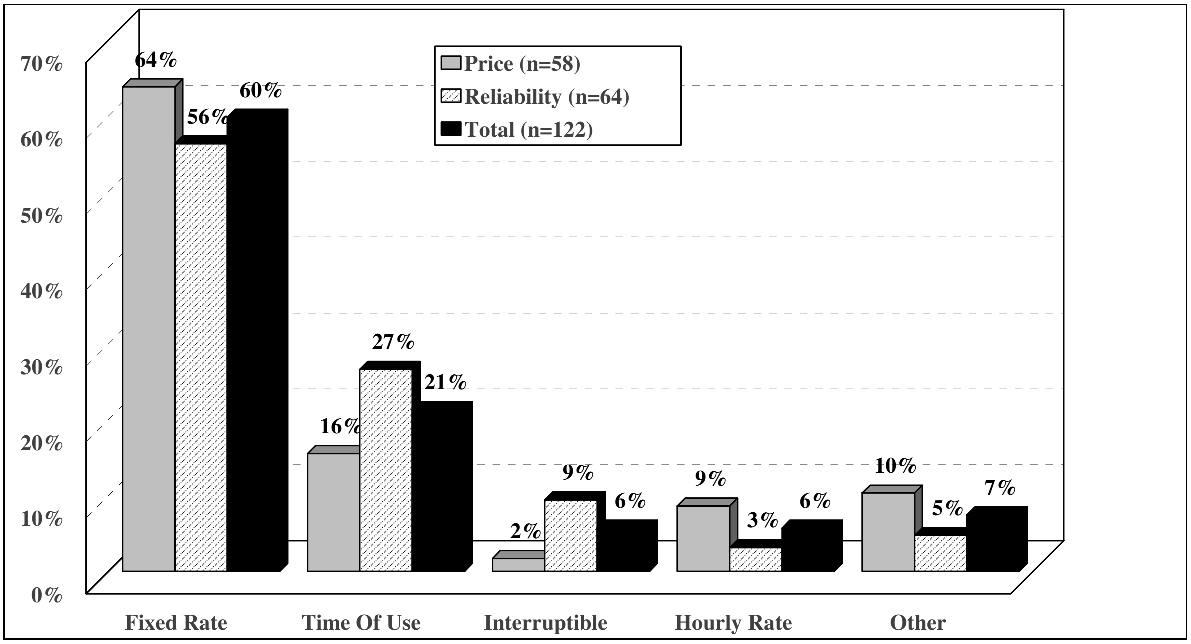


Figure 4-7: Electricity Supply Purchases Fixed versus Time Varying

4.4.4 Load Management Capability

Respondents were asked to describe actions they took when they were asked to curtail during events. Figure 4-8 displays the frequency of the actions reported as a percentage of the total respondents and compares the results to those from last year's study.[26] In general, price customers were more likely to implement actions such as turning off lighting or adjusting HVAC temperatures, while reliability customers were more prone to running generators or shifting manufacturing processes. The single biggest change from 2004 to 2005 was the increase in the frequency of generator use among reliability customers, which increased from about 25% to about 58% of reliability customers, and was the single most employed action in either year.

[26] Since one customer can implement multiple actions the sum frequencies for either the price or reliability customers will be greater than 100%.

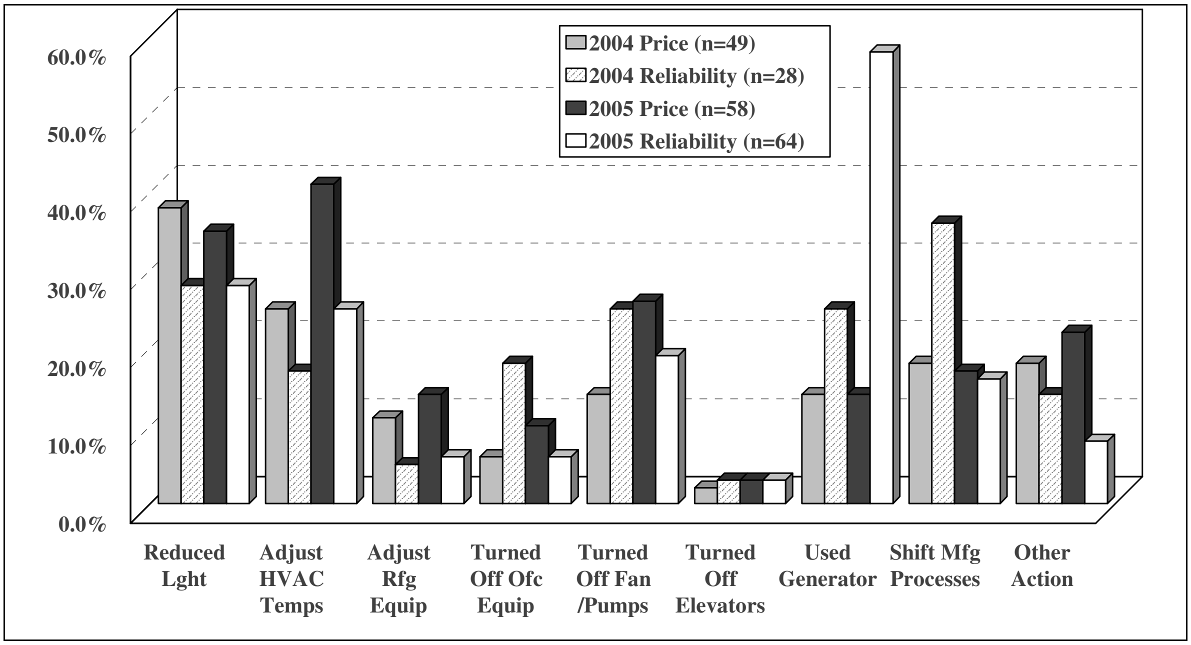


Figure 4-8: Actions Undertaken During Events

4.4.5 Barriers to Participation in Current Program Offerings

Price program participants were asked to indicate why they did not participate in the Reliability Programs (Figure 4-9). Approximately, 43% of the respondents to the 2005 survey indicated that they were unable to shift usage and another 25% indicated that inadequate program knowledge were the primary barriers to participation. Permitting issues were cited by 4% of the 2005 respondents. The remaining 28% indicated that the financial incentives were too low. These results are similar to those reported by the 2004 Price Program survey respondents.

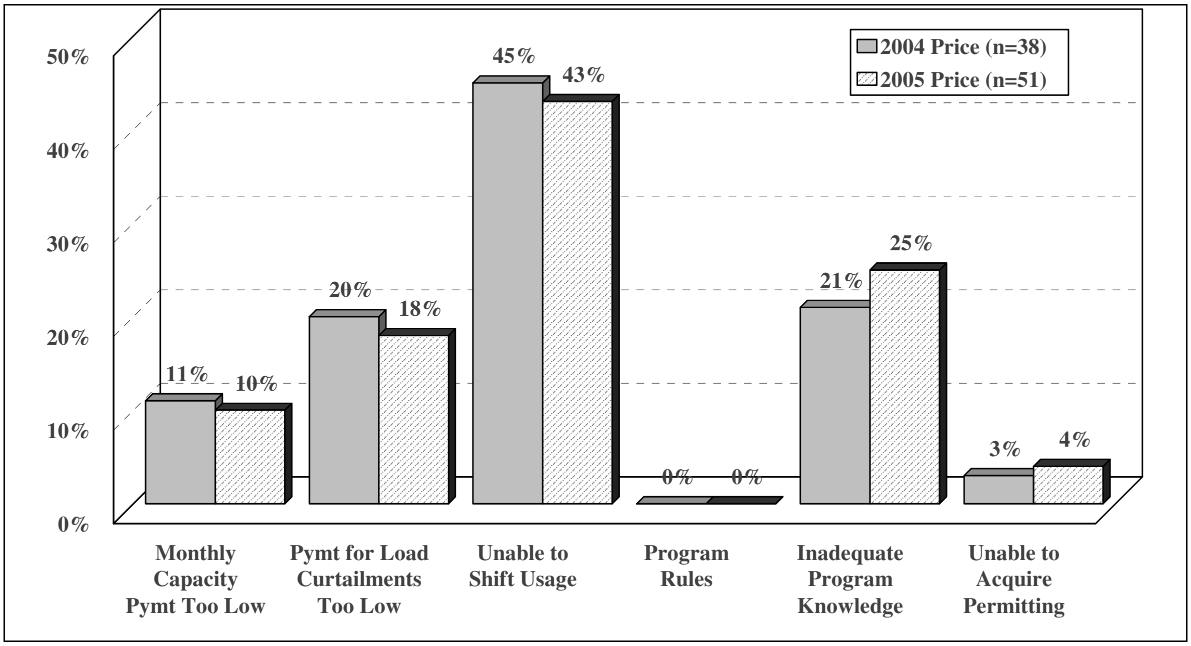


Figure 4-9: Price Customers Reasons for not Participating in the Reliability Programs

Given the current state of the capacity market in New England, characterized by low monthly ICAP supply market prices, it is not surprising that many customers find participation in the Reliability Programs not to be economically attractive. ICAP payments to Reliability Program participants were relatively low throughout 2005, averaging about $0.17/kW-month.[27] Consequently, energy payments ($/kWh) during reliability events are the primary source of revenue for customers participating in Reliability Programs.[28] For many customers, the expected revenue from energy payments does not justify undertaking the transactions required to successfully participate in Reliability Programs.

[27] All Reliability Program participants receive ICAP credits that can be monetized through ISO-NE's monthly ICAP supply auction.

[28] The exception are customers participating in the 30-Minute Real-Time Demand Response program located in SWCT that are eligible for supplemental capacity payments from suppliers under contract to ISO New England as part of the SWCT Gap RFP.

The inability to clearly distinguish the survey response of a typical Reliability and Price Program participant, as well as the inconsistencies in both customer behavior and opinions revealed by the survey, may be reflective of the relative immaturity of the demand response market. This is not unusual for customers who are the early adopters of new products and services. In the case of demand response, participating customers are still learning what they can and cannot accomplish in terms of the amount and frequency of load reductions. In other words, many are experimenting in Real-Time to extract value out of the product. However, since the economic benefits of demand response are relatively small when compared with the amount of money spent on energy commodity and with traditional energy efficiency projects, most customers cannot justify devoting a significant amount of time and resources to master the programs. This contributes to the inconsistency in customer behavior and, if unchanged, may stall further participation in the programs.

A challenge facing ISO-NE is to successfully bridge the gap between the early adopters of demand response and the more mainstream customers who will need clear examples and value propositions to entice their participation. Providing technical assistance and developing case studies can help bridge this gap.

Customers would likely take advantage of technical assistance to help quantify the amount and methods of load reduction, if their Enrolling Participant, Demand Response Providers, or Local Distribution Company offered it. One Massachusetts-based local distribution company is currently offering technical assistance (funded through the States' energy efficiency funds) to its customers in the form of a Load Reduction Audit. The Load Reduction Audit provides customers with estimates of what they can accomplish through the program, as well as a plan for achieving their goals. In addition to helping the individual customer, the results of the Load Reduction Audits can be used to develop case studies to help other customers evaluate whether to participate and then choose the program best suited for them.

4.4.6 Alternative Design and Product Preferences

Almost 500 customers chose to participate in the ISO-NE Real-Time Price Response Program in 2005. That choice reflects customer preferences for a program that pays only for performance, and lets customers decide when and how to curtail. The tradeoff relative to the Reliability Programs is that the Price Program offers no monthly capacity payment through the ICAP market. Moreover, price response program participants have no assurance that opportunities will arise to curtail and get paid, since payment is limited to when ISO-NE forecasts Real-Time LMPs in excess of $0.10/kWh, and activates the program. This strong interest in responding to market prices (as opposed to committing to reducing load during a system emergency) suggests that there might be a substantial interest in participating in the Day-Ahead Option.

The survey assessed customer knowledge of and interest in the Day-Ahead Option. Figure 4-10 shows that respondents generally were not very familiar with the Day-Ahead Option, with price response customers reporting a slightly better level of familiarity.

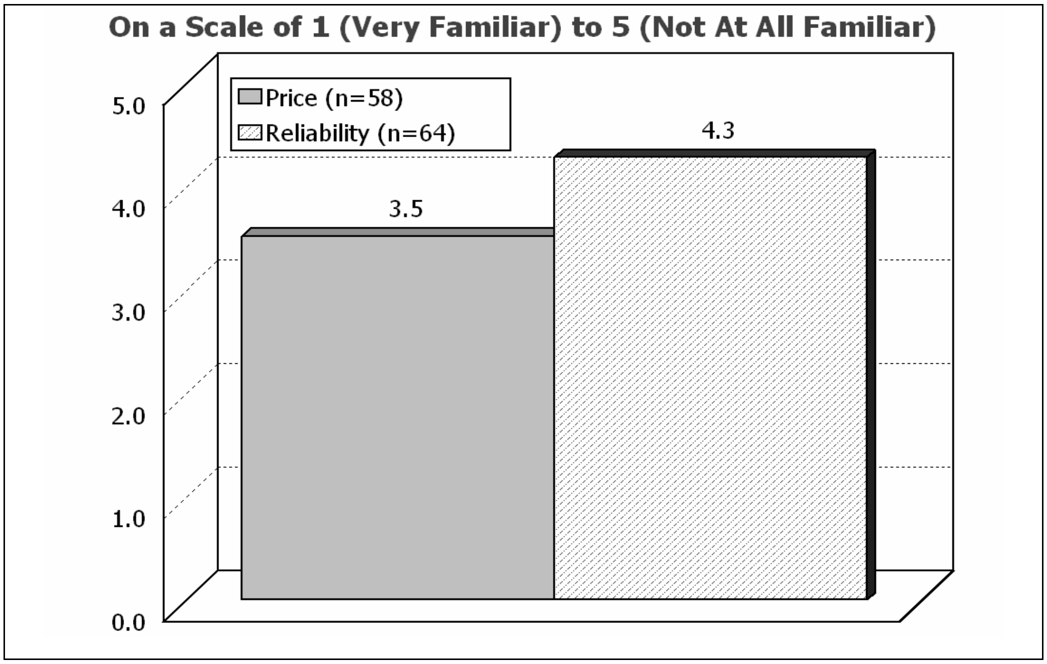


Figure 4-10: Familiarity with Day-Ahead Option

Respondents who were at least moderately familiar with the Day-Ahead Option (1, 2, or 3) were then asked to indicate the likelihood that they would participate in it. As Figure 4-11 shows, neither survey group reported being very likely to participate, although the price customers were more inclined to than the reliability customers.

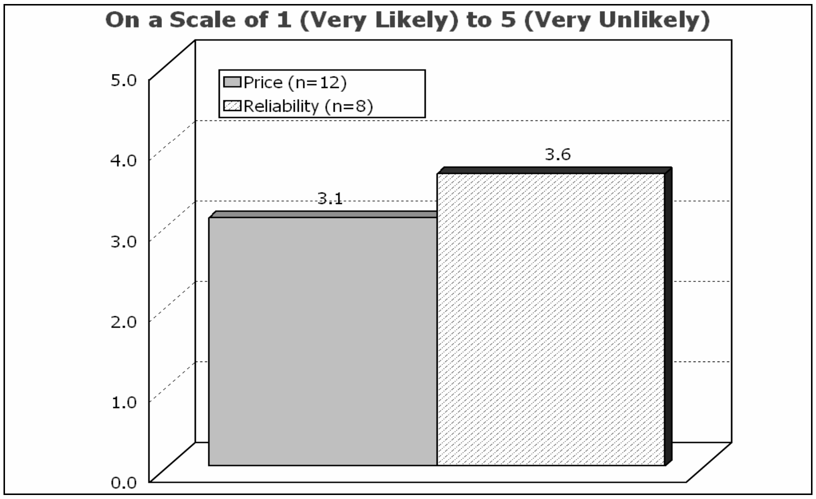


Figure 4-11: Likelihood of participating in the Day-Ahead Demand Response Option

Respondents providing a 4 or 5 ranking to the previous question were asked to indicate why they responded this way. Table 4-5 shows that 50% of these customers (primarily the price customers) do not want to be exposed to the non-performance penalty of the Day-Ahead Option.

Why Not?	Price (n=4)	Reliability (n=4)	Total (n=8)
Don't Want Exposure to Potential Penalty for Non-Performance	3	1	50.0%
Can't Determine How Much Load to Shed	0	1	12.5%
Can't Determine the Price to Bid	1	0	12.5%
Don't Know How to Submit Bid (the process)	0	1	12.5%
My Enrolling Participant is Not Offering the Option	0	1	12.5%

Table 4-5: Why Are You Unlikely to Participate in the Day-Ahead Option?

4.4.7 Price Program Survey Results

The Price Program participants were provided the following table (Table 4-6), which presents the frequency of price events called from January-July 2005 by Load Zone, and asked how they felt about the frequency of the events. For comparative purposes, the table also provides the number of events called from January through June in 2004.

	ME	CT	NEMA	SEMA	WCMA	NH	VT	RI
January	15	15	16	15	15	15	15	15
February	5	7	6	6	7	6	7	6
March	9	10	12	10	10	9	10	10
April	9	11	18	10	12	11	11	10
May	2	6	15	3	4	2	3	3
June	7	16	18	9	9	8	9	9
July	16	17	18	16	16	16	16	16
Jan-Jul 2005 Total	63	82	103	69	73	67	71	69
Jan-Jun 2004 Total	11	28	21	17	23	18	22	17

Table 4-6: Frequency of Price Events by Load Zone, January-July 2005

As illustrated in Figure 4-12, over 70% of the 2005 price survey respondents felt that the number of events was the right amount, down 10% from the 2004 results. Although the number of events increased drastically in 2005 compared to 2004, only 10% more respondents felt that there were too many events were called. Once again 3% of respondents felt that there were not enough events in 2005 the same percentage as in 2004. These data indicate that even though the number of events increased dramatically during 2005, the majority of the program participants do not view this as a problem.

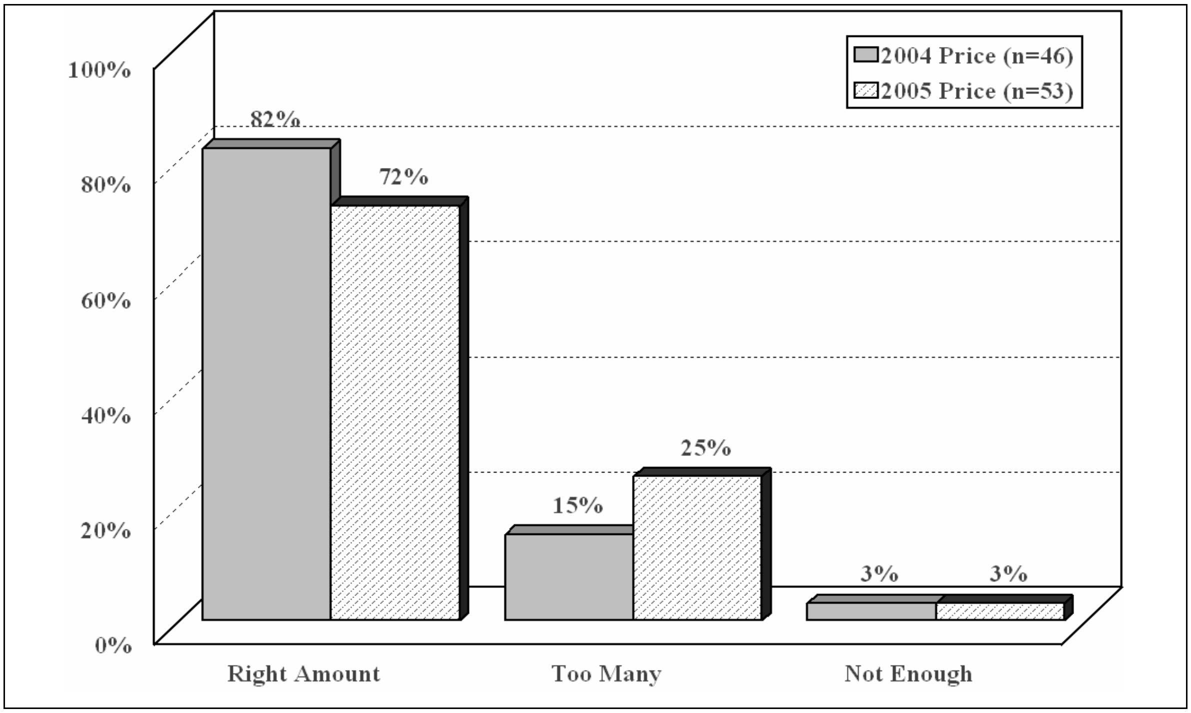


Figure 4-12: Frequency of Price Event and Customer Participation Percentage

Finally, the Price Program participants were asked whether they actually checked the LMP while making the decision to curtail, and to indicate the minimum price at which they would curtail load. Figure 4-13 shows that 75% of the 2005 price survey respondents make a decision on whether to participate in a price event without even considering the LMP, which is a 6% increase from the 2004 results. Note that 16% of the 2005 respondents indicated that their minimum price to curtail load was greater than \$0.50/kWh – there were no customers in 2004 with a minimum price this high.

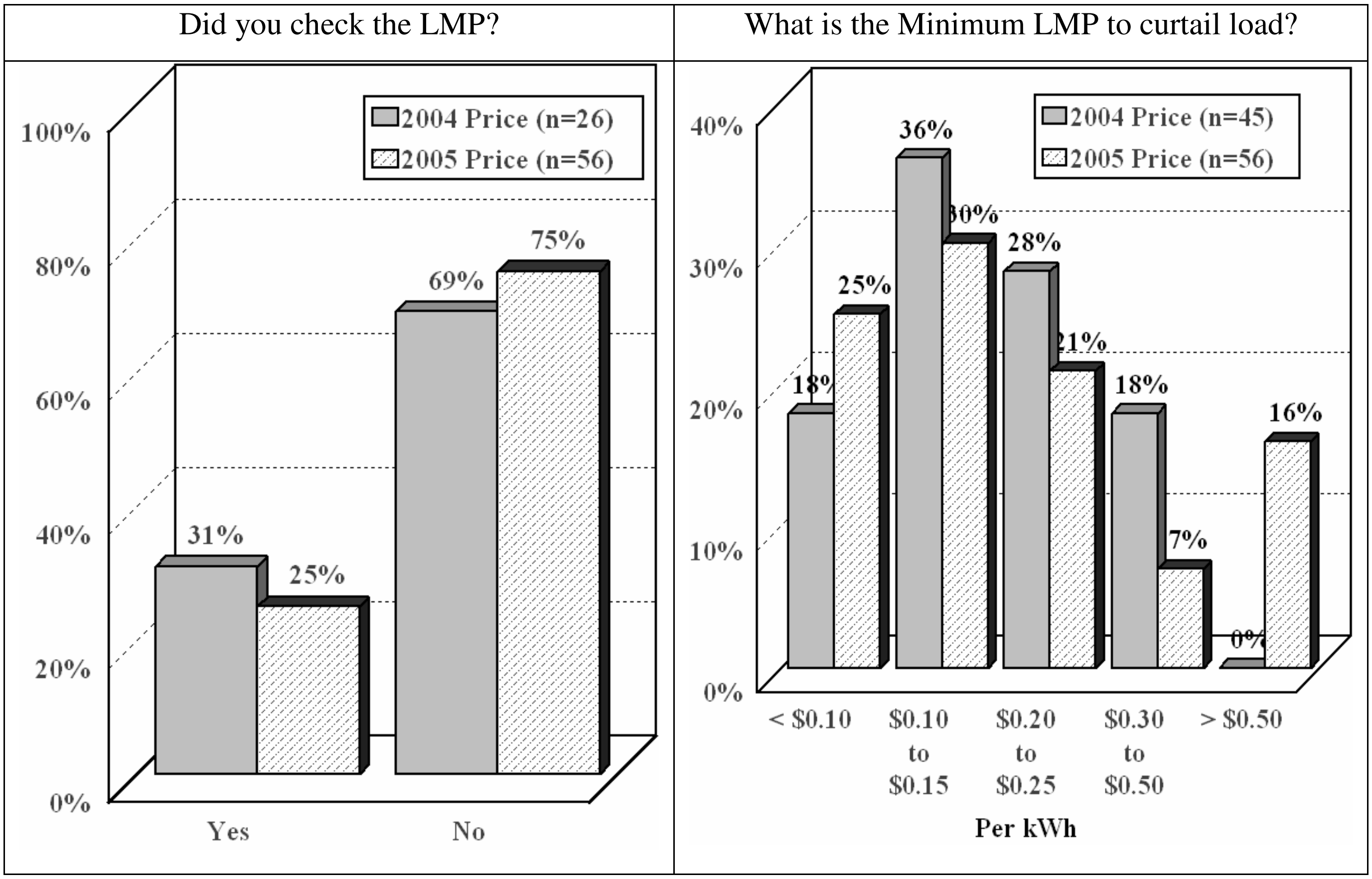


Figure 4-13: Did you Check the LMP/ and What is the Minimum Price to Curtail?

The results above are probably due, in part, to the guaranteed minimum floor payment of $0.10/kWh for all event hours, as 57% of respondents reported that they probably wouldn't have enrolled without this guarantee.

Customers were asked what they would do if the $0.10/kWh guarantee was eliminated, but Price Events were called only when Real-Time prices were likely to be at or above $0.10/kWh. Figure 4-14 shows that 60% would remain in the program, while 32% would monitor prices before deciding to participate. Note that 11% of respondents indicated that they would participate in the Day-Ahead Option and 13% indicated that they would leave the price response program and buy energy at a fixed rate.[29] None of the respondents expressed interest in leaving the Price Program and buying energy at a variable rate.

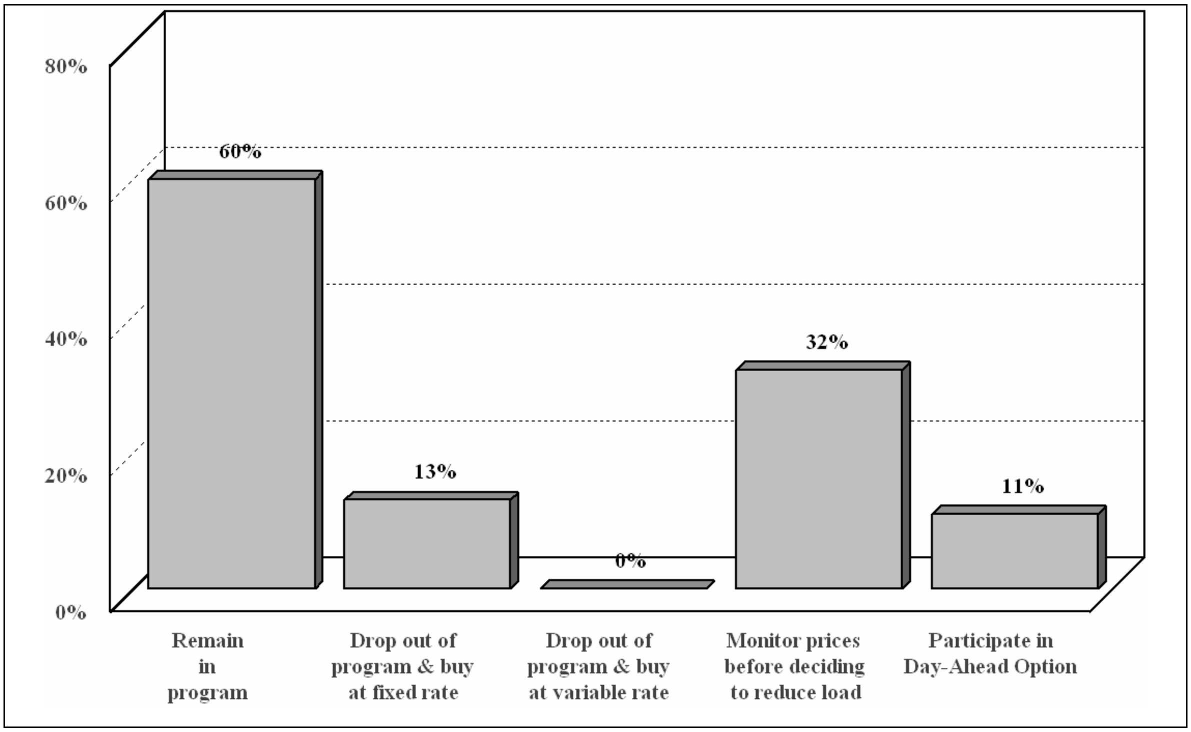


Figure 4-14: What would you do if guarantee was eliminated, but events were called only when Real-Time prices were likely to be at or above $0.10/kWh?

4.4.8 Reliability Program Survey Results

Reliability participants were asked to rank the importance of various program features in their decision to participate. As Figure 4-15 shows, the payment for load curtailment was the most important feature with a ranking of 2.4, while the metering package and Internet access was the least important feature, with a ranking 4.4.

[29] Customers were allowed to select all applicable responses so the percentage total for all response exceeds 100%.

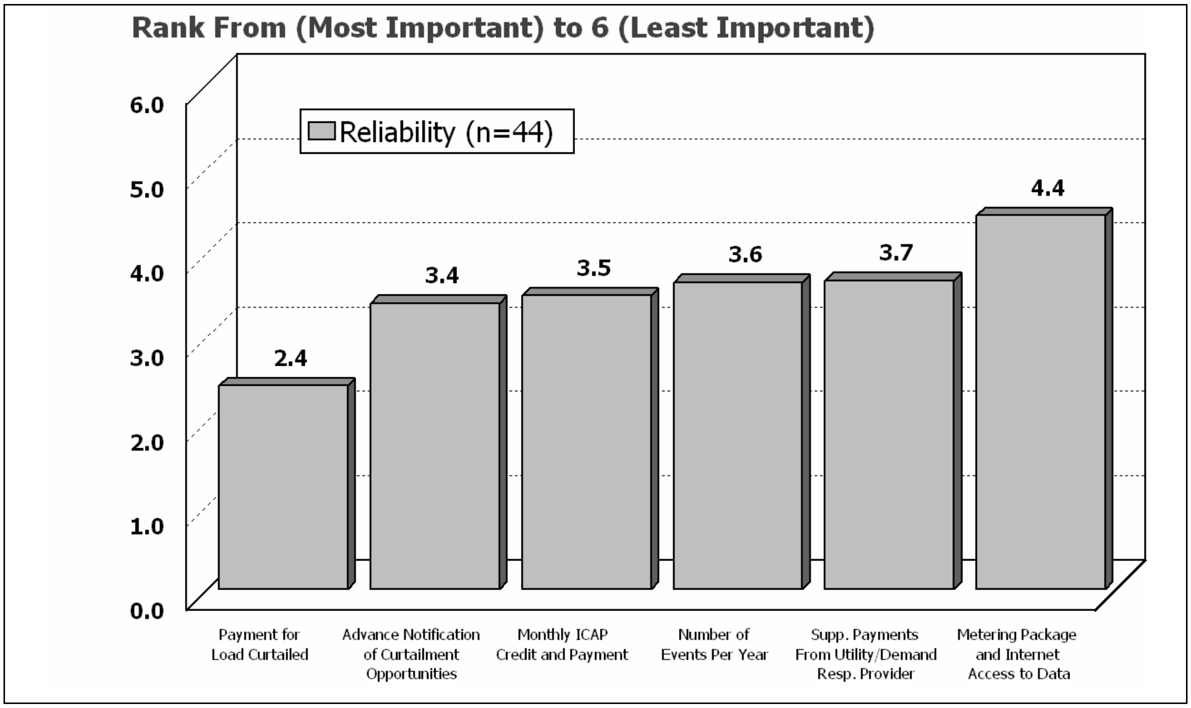


Figure 4-15: Importance of Program Features in Participation Decision

5 Market Assessment

The 2004 market assessment estimated the demand response potential for ISO-NE's programs using primary and secondary information sources for four general usage sectors: Residential, Commercial, Industrial, and Other. There have been no significant changes to New England's sector makeup since the 2004 market assessment. Rather than simply reiterating the 2004 estimates, this year the market assessment will focus on an alternative strategy to achieve Price Responsive Demand in New England.

Over the past three decades electricity customers in New England have lowered electricity costs by improving energy efficiency. Conservation and load management (C&LM) programs offered by New England's utilities have helped thousands of residential, commercial, and industrial customers to become more energy efficient. Despite these efforts, few retail customers have been able to *proactively* lower the average price they pay for electricity. The price for electricity (¢/kWh) paid by most New England customers is a fixed number, set by either a state commission order or through a periodic negotiation with a competitive supplier.

Retail customers in New England could lower the average price they pay for electricity by changing their electricity consumption pattern in response to changes in the wholesale electricity prices. Demand that changes in response to changes in wholesale price is called Price Responsive Demand. Price Responsive Demand is a powerful, yet virtually untapped tool that state regulators and public policy makers can use to help customers better mange their energy costs. Price Responsive Demand can be achieved by several different methods. ISO-NE's Real-Time Price Response Program is one such method. However, a "program approach" to accomplishing Price Responsive Demand results in transfer payments from one group of market participants to another (as described in Section 3) and has inherent program design challenges such as the price event triggering mechanism (as described in Section 1). An alternative, and likely more effective method, is to encourage "naturally occurring" Price Responsive Demand through the use of Time-Based rates such as prices indexed to the wholesale Day- Ahead Market.

Unlike traditional fixed price rates that most customers are familiar with (i.e., "use as much as you want when ever you want, it all costs the same"), Time-Based rates vary the price of electricity over the course of a day and season. The value of Time-Based rates to consumers is that retail customers who reduce their electricity consumption coincident with high wholesale prices not only lower their own costs but also lower wholesale prices for *all* customers within their Load Zone and/or region. As described in Section 3, reducing demand at times of high wholesale prices can reduce the wholesale price of electricity in both Real-Time, as well as for suppliers purchasing future hedge contracts. In addition, since high wholesale prices are often times coincident with peak demand, Price Responsive Demand may also reduce peak load, which results in a reduction in fuel and operating costs and the need for capacity. Additionally, the emissions from inefficient units that are run only to meet peak loads would be avoided, resulting in a cleaner environment. Thus, society as a whole benefits from the behavior of those customers on Time-Based Rates. Time-Based Rates are a "win-win" situation for all customers. It is because of these benefits that The New England Demand Response Initiative (NEDRI) recommended in 2003 that state utility commissions consider taking actions including the following:

- Implementing a Real-Time price component in the generation costs assessed to large-volume default service customers,
- Expanding the deployment of sophisticated metering to default service business customers whose demand is 100 kW or greater,
- Implementing time-sensitive pricing structures for medium and low-volume (i.e., mass market) default service customers,
- Initiating a process to consider more fully the costs and benefits of deploying advanced metering, and of the pricing options such metering will make possible, to mass market customers, and

- Taking related actions to reform default service and load profiling so as to improve both the incentives and means (among customers and suppliers) for acquiring demand response.[30]

ISO-NE recently sponsored a study to estimate the impacts of implementing Day-Ahead Indexed Default Service (DADS) throughout New England – i.e., default service rates indexed to ISO-NE's Day-Ahead Energy Market. The preliminary results of the study are currently under review by various New England State Utility Commissions. ISO-NE plans to release the final report on or about April 27, 2006, in conjunction with its 2006 New England Demand Response Summit.

Research from the preliminary study was used in this market assessment to develop an estimate of the potential for Price Responsive Demand from large commercial and industrial customers through DADS.

5.1 Defining the Market

In order to assess the market potential for Price Responsive Demand in New England, it is first necessary to estimate the size of the market that would likely participate in DADS. For the sake of this analysis, the potential participants are defined as commercial and industrial (C&I) customers with peak demands of 100 kW or greater that are purchasing electricity from their Local Distribution Company (LDC). The relative price responsive behavior of C&I customers will be estimated by applying price elasticities to peak demands to estimate how customers would alter their usage pattern when facing hourly prices indexed to the Day-Ahead wholesale market prices. Moreover, because studies indicate that price response varies among customer segments, the C&I customers in New England must be segmented by business category.

[30] New England Demand Response Initiative, July 23, 2003. "Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets." Available at: http://nedri.raabassociates.org/Articles/FinalNEDRIREPORTAug%2027.doc

5.1.1 Commercial and Industrial Loads

Aggregate and individual customer demand data were collected to characterize virtually all of the major LDCs operating in CT, NEMA, SEMA, WMCA, and RI load zones as well as a large portion of the ME and NH load zones. These data included customer counts and peak demands by Standard Industrial Classification (SIC) code. Secondary sources were used to augment the load data for the ME and NH zones.[31] Since no comparable customer data was available for Vermont, customer segment data were synthesized using New Hampshire segment data matched to Vermont customer account data.

End-use customers were assigned to one of five business categories based on their two-digit SIC code as follows: Manufacturing (SIC 01 – 39); Public Works (SIC 40 – 49); Commercial/Retail (SIC 50 – 79); Health Care (SIC 80); and Government/Education (SIC 81 – 98). Within each business category, customers were assigned to one of five maximum demand groups using the following maximum demand ranges: 100-499 kW, 500-999 kW, 1.0-1.9 MW, 2.0-4.9 MW, and 5 MW and above.

Table 5-1 below shows the distribution of C&I customers with peak demands greater than 100 kW (count and maximum demand) by business category for each Load Zone. Manufacturing and Public Works were assigned to the Industrial segment, while Commercial & Retail, Health Care, and Government & Education categories were assigned to the Commercial segment.

[31] Two additional sources were consulted to confirm customer counts and demands: FERC Form 1 and the Energy Information Administration. Customer segmentation by region, business type and size was submitted to ISO-NE for reasonableness prior to its use in the assessment.

	Industrial				Commercial						Total C/I	
	Manufacturing		Public Works		Retail		Health		Government/ Education			
Zone	Count	Total MW	Count	Total MW	Count	Total MW	Count	Total MW	Count	Total MW	Count	Total MW
CT	1,047	573	226	319	1,567	529	198	98	902	302	3,940	1,821
ME	182	592	2,298	76	95	92	34	44	36	47	2,645	851
NEMA	675	483	245	120	2,475	989	268	193	1,273	503	4,936	2,289
NH	72	33	8	2	14,493	35	8	12	42	20	14,623	101
RI	658	338	115	56	890	264	113	56	499	194	2,275	907
SEMA	796	494	160	68	1,383	393	150	60	556	168	3,045	1,183
SWCT	660	475	202	116	1,167	447	130	83	634	219	2,793	1,340
VT	-	0	-	0	-	0	-	0	-	0	-	0
WMCA	1,168	849	273	228	1,626	524	224	104	969	364	4,260	2,069
Total	**5,258**	**3,836**	**3,527**	**986**	**23,696**	**3,273**	**1,125**	**651**	**4,911**	**1,815**	**38,517**	**10,561**

Table 5-1: Distribution of C&I Customer by ISO-NE Zone

There are approximately 8,800 Industrial customers in New England with a total peak demand of about 4,820 MW and an average peak demand per customer of about 550 kW. By contrast, the total peak load contribution from Commercial customers was roughly equal at about 5,740 MW, but there were more than three times as many customers (more than 29,700). A total of over 38,500 C&I customers with a total peak demand of more than 10,560 MW were included in the analysis.

5.2 Defining Customer Price Elasticity

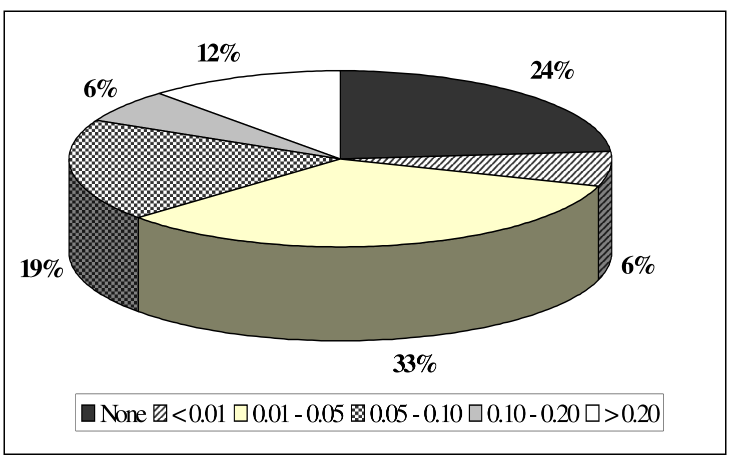


Figure 5-1: Distribution of Customer Demand by Elasticity of Substitution

The level of reduction in demand due to DADS was estimated using an analysis of Niagara Mohawk Power Company (NMPC) SC-3A customers (Goldman *et al.*, 2005). NMPC's SC-3A customers purchase electricity on an hourly rate indexed to the New York Independent System Operator's (NYISO) Day-Ahead Market price. In the NMPC analysis, individual customer-level demand models were estimated, yielding daily estimates of the elasticity of substitution for each customer.[32] The daily elasticity values could then be aggregated by business sector to produce a measure of price-responsiveness at a higher level of detail (see Figure 5-1).[33] Nearly a quarter of the analyzed SC-3A class' demand showed no price elasticity at all, while an additional 39% of the load had a price elasticity of less than 0.05. Only about 18% showed a substantial degree of price response, defined by an elasticity value of 0.10 or above.

Average business class price elasticities for the NMPC customers range from a high of 0.16 for Manufacturing to a low of 0.02 for Public Works. The price elasticities for the other classes ranged from 0.04 to 0.10 as illustrated in Table 5-2. The individual estimates exhibit a wide range of values, even within sectors, indicating there are additional drivers to a firm's price responsive ability aside from business class.

	Elasticity of Substitution		
Business Class	Min	Avg	Max
Commercial / Retail	0.05	0.06	1.49
Gov't / Education	0.09	0.10	0.42
Health Care	0.03	0.04	0.04
Manufacturing	0.15	0.16	0.18
Public Works	0.01	0.02	0.02
Total	**0.10**	**0.11**	**0.38**

Table 5-2: NMPC Estimates of Elasticity of Substitution by Business Class

[32] The elasticity of substitution represents the percentage change in peak to off-peak load ratio for a 1% change in the off-peak to peak price ratio. In the study sponsored by ISO-NE to estimate the impacts of DADS on the wholesale market, customers were assumed to compare the DADS rate to what they otherwise would have received on their default rate, and the difference provides the motivation to alter their daily consumption pattern. The higher the difference in price, the greater the amount of load reduced.

[33] Since these elasticity values are load-weighted by their maximum peak demand, they represent what the business class as a whole would provide in terms of demand response. This type of characterization embodies the fact that some customers simply do not respond at all, while others provide sizable load reductions. In the end, the system sees the result of the entire class' behavior – a load-weighted average response. The exact location of these resources may affect the level of response, especially if the highly responsive customers are located in load pockets within a zone.

The distribution of elasticities can be simplified by assigning customers into one of three categories. The first contains customers who are either unwilling or unable to respond to prices whatsoever (i.e., Non-responsive). The second group represents those who respond, but only in a very limited fashion (i.e., Un-responsive). They have positive, but small elasticities that are less than 0.05. The last group is able to respond, in some cases robustly so, when the market conditions warrant such behavior (i.e., Responsive). These customers have elasticities of substitution in excess of 0.05. A summary of the elasticities of substitution for each customer group is presented in Table 5-3.

	Elasticity of Substitution							
	None		< 0.05		> 0.05		**Overall**	
Business Class	% of Total	Avg. Elast	% of Total	Avg. Elast	% of Total	Avg. Elast	**% of Total**	**Avg. Elast**
Commercial / Retail	36%	N/A	40%	0.02	24%	0.21	**100%**	**0.06**
Gov't / Education	21%	N/A	34%	0.03	45%	0.21	**100%**	**0.10**
Health Care	2%	N/A	93%	0.04	4%	0.07	**100%**	**0.04**
Manufacturing	24%	N/A	32%	0.03	43%	0.34	**100%**	**0.16**
Public Works	43%	N/A	46%	0.01	11%	0.09	**100%**	**0.02**
Total	**24%**	**N/A**	**40%**	**0.03**	**37%**	**0.27**	100%	0.11

Table 5-3: Distribution of Elasticity of Substitution by Level of Responsiveness and Business Class

5.3 Estimating the Level of Price Response

The preliminary results of the study sponsored by ISO-NE includes estimates of the potential for peak load reductions (i.e., Price Responsive Demand) from large C&I customers under a variety of different market circumstances. In particular, three market conditions were created to represent three states of capacity and demand levels in New England. In times of excess capacity and relatively low demand growth, it would be expected that the ISO-NE energy market would clear at consistently low prices. Should the capacity situation become tighter due to increased load growth and/or plant retirement, the market should experience slightly higher prices, with more frequent price spikes. If capacity becomes short and load exceeds expectations due to weather or other factors, the electricity market would see historically high prices along with very frequent price spikes. These three market conditions could be characterized simply as Low, Moderate, and High, respectively.

Table 5-4 contains estimates of peak demand reductions from the C&I sector by customer-demand threshold for DADS using a range of different market outlooks (i.e. Low, Moderate, and High). The data is presented in descending order of customer size – based on customer peak demand – placed on DADS. For example, the first row provides the resulting amount of Price Responsive Demand if DADS is implemented only to C&I customers with peak demands of 5,000 kW or greater. If DADS were implemented for all C&I customers with peak demands greater than 100 kW, the resulting Price Responsive Demand would range between 604 MW and 701 MW depending on the level of Day-Ahead Energy Market prices. ISO-NE plans to release the final study concerning DADS implementation, which includes a detailed description of the analysis and methodology, on or about April 27, 2006.

Estimated Range of Price Responsive Demand			
Demand Threshold	**Low (MW)**	**Medium (MW)**	**High (MW)**
5,000 kW & Greater	122	130	141
2,000 kW & Greater	222	238	258
1,000 kW & Greater	307	328	357
500 kW & Greater	413	441	479
100 kW & Greater	604	646	701

Table 5-4: Preliminary Simulation Results of Price Responsive Demand from DADS Implementation

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and Related Agencies | **December 1, 2005**

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New Hampshire

The Honorable John H. Lynch State House 25 Capitol Street Concord, NH 03301	New Hampshire Public Utilities Commission 21 South Fruit Street Suite 10 Concord, NH 03301-2429

Rhode Island

The Honorable Donald L. Carcieri State House Room 115 Providence, RI 02903	Rhode Island Public Utilities Commission 89 Jefferson Boulevard Warwick, RI 02888

Vermont

The Honorable James Douglas 109 State Street, Pavilion Montpelier, VT 05609	Vermont Public Service Board 112 State Street, Drawer 20 Montpelier, VT 05620-2701

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., this 30th day of December, 2005.

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