Synapse
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Demand Response Potential in ISO New England's Day-Ahead Energy Market

A Report for the Attorney General of the Commonwealth of Massachusetts

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Executive Summary

This report summarizes research regarding the potential cost reduction impacts of demand response resource participation in the ISO New England wholesale day-ahead energy market. We find that demand response participation impacts can vary a great deal from season to season and year to year based on a variety of factors. While common assumptions about peak demand causing high prices are generally true, the correlation is not strong enough to generate confidence in a mechanism that uses demand or price levels as a threshold for demand response participation.

After examining four years (2006-2009) of ISO New England hourly data using four different approaches to demand response (DR) participation (High Load, High Price, Fixed DR, and Computed DR) we estimated the net cost savings summarized in Table ES.1, below. Not only do the cost savings vary a great deal between the four approaches, the quantities of demand resources needed to achieve those savings vary from less than 1,500 MW (the High Load case) to over 6,000 MW (High Price case) and, to over 15,000 MW (Computed DR case).

Table ES.1 Potential Net Savings from DR Participation in Four Cases

	Correlation Adjusted Net Savings , mln $		Net Savings , mln $	
Year	High Load Case	High Price Case	Fixed DR Penetration Case (10%)	Computed DR Penetration Case
2006	176	29	949	1,485
2007	207	18	1,168	2,307
2008	234	43	1,348	3,847
2009	137	15	162	145

Lastly, we analyzed a single supply stack for one day. We adjusted the supply stack with specific quantities of demand response offers and determined that the potential savings from demand response participation varied a great deal within that single supply stack. There are flat segments to the supply stack at various places, including blocks at high prices, where small amounts of demand response participation would increase overall costs in the DA market.

To prevent such increases, we recommend that a dynamic threshold mechanism, such as the method developed by the Consumer Demand Response Initiative (CDRI), be used to evaluate demand response offers in the DA energy market. The CDRI method is a simple benefits test and it is the only analysis necessary to select the optimal combination of resources (generation and demand response) to meet the DA load. The CDRI algorithm also provides a way to allocate costs to the DA load that is transparent and directly linked to the entire load in the DA market that receives the benefits of demand response participation. Factors that are external to the wholesale energy market, such as retail rates, enhanced reliability, and reduced emissions, do not need to be addressed to provide comparable treatment to both demand and generation resources. Assertions that savings in the DA energy market will be exceeded by higher costs in the capacity market are not supported and misrepresent how competitive markets function.

I. Introduction

Demand response resources have participated in wholesale electricity markets for the last dozen years in New England, New York, and the mid-Atlantic regions. Even prior to organized wholesale markets operated by ISOs and RTOs, demand response resources have been available to system operators through a variety of utility sponsored programs and rates. This participation over the years has been in recognition of the dramatic impact that demand response resources can have on both reliability and prices when the supply stack has a steep slope (for example, the 100 hours each year with the highest prices). Less well known is the impact that demand response resources would have at the less steep portions of the supply stack

This study examines the potential for demand response resources to affect day-ahead energy markets through robust participation in those markets as a supply resource. We examine the New England historical day-ahead energy market data for the last four years (2006-2009) and make several assumptions about demand response participation in the day-ahead wholesale energy market. We examine participation based on highest loads and prices (High Load and High Price cases) and participation based on the average slope of the offer stack for each day (Fixed DR and Computed DR cases). In addition, we analyze one specific supply stack for a single day and show the impact of 200 MW of demand response resources.

This last approach, the analysis of a supply stack for one day, provides the most reliable estimate of potential savings from DR participation, because it has to deal with the variability of the daily offer stack rather than using simplifying assumptions. Although loads correlate with high prices, this correlation is not very strong: high loads do not always produce high prices and high prices occur sometimes when loads are quite low. There are many other variables (besides load levels) that influence day-ahead energy market prices. Load forecast and weather forecast accuracy are the two most often noted. Seasonality is becoming more important due to the small maintenance outage windows available in the spring and fall. The types of resources available (flexible versus inflexible) can also contribute to significant price changes day to day, as do specific generation unit and transmission line outages.

The key assumption underlying all the savings calculations that we present is that specific quantities of demand response resources would respond in each hour when the day-ahead price exceeds an identified threshold.[1] The price threshold in the High Load and High Price cases varied dynamically (hour by hour) and reflected seasonal changes as well as fuel-price changes. The Supply Stack Slope cases used ISO New England's monthly static threshold price. All the cases in this report assume that the demand resources would receive compensation equal to DA LMP for every hour in which they clear as a Day-Ahead resource.

[1] The price threshold we used in the High Load and High Price cases were determined by each 1% slice of hours that we analyzed. For the Supply Stack Slope case, we used ISO-NE's monthly threshold prices and extrapolated back in time based on gas prices.

Despite the uncertainty of the savings estimates, the general directionality, and size of the savings follow reasonably congruent outcomes. In general, savings are higher in the summer months but not in all years. When marginal fuel prices are low or when weather significantly reduces loads, demand response savings dwindle. Demand response participation in 10% of the highest load or highest price hours will lower energy market prices towards the flat part of the offer stack, in most cases close to the offer price of baseload power.[2]

II. Methodology and Results

The most precise way to estimate savings from demand response participation in the day-ahead energy market would be to use a known offer curve for demand response[3], align that offer-curve to the existing stack of offers from all resources, and re-dispatch the system on an hourly basis with those new offers included. Even with such a detailed approach, the actual re-dispatch of the system might not pick up some of the subtle adjustments based on resource offer parameters and the ISO's goal of "lowest daily production cost" in light of all system variables including local transmission limitations. Most importantly, we do not have day-ahead offer data for demand resources and, therefore, have no way to construct an offer curve. [4]

Instead, we used assumptions about the availability of demand response resources at specific price levels. We then examined the likely impact on prices and system costs if the assumed quantities of demand response resources participated at those price levels. We first looked at DR participation from two perspectives based on the general correlation between high loads and high prices (the High Load and High Price cases). Our second approach was to look at DR participation based on the slope of each day's supply stack (the Fixed DR case and the Computed DR case).

The four cases provide ways to estimate the potential savings from robust DR participation in the day-ahead energy market:

- the impact of DR offering during high load hours (High Load Case];
- the impact of DR offering during high energy price hours (High Price Case);
- the impact of a fixed quantity of DR offering and the slope of the day-ahead supply stack (Fixed DR Case); and

[2] DR participation in more than 10% of the highest load or highest price hours will still provide additional reductions in total daily cost. Given today's maximum participation rates of 1% or less, concern over the impacts of participation rates greater than 10% are unnecessary at this time.

[3] An offer curve for demand response (preferably based on actual demand response participation) would eliminate the need to make assumptions about "how much" DR is available at various prices.

[4] The closest example we have of such an analysis is one done by PJM after a heat wave in the summer of 2006. Over five days, demand response participation reduced clearing prices by $650 million; direct payments to demand response totaled $5m. *See*, Demand Response in Wholesale Markets, FERC Docket No. AD07-11-009, testimony of PJM witness Andrew Ott, April 23, 2007, page 7.

- the impact of a calculated quantity of DR offering and the slope of the day-ahead supply stack (Computed DR Case).

All four cases of DR participation show substantial potential net savings, although savings vary significantly from case to case, year to year and season to season. The savings totals for each case are the difference between the total costs for each hour prior to DR participation and the total costs for each hour after DR participation. The payments to the DR resources are subtracted from the change in costs to provide the net savings in each hour. The hours are then summed to provide the annual net savings. In the High Load and High Price cases, we further reduce the annual net savings by the seasonal correlation factors. In all cases, the demand response offers that clear are paid the DA LMP for the hours in which they participate. We did not include any externalities in our calculation of net savings.[5]

A. Potential DR Savings Based on Peak Prices and Loads

Our first approach for estimating potential savings from DR participation involved a way to compare savings based on DR participation at a series of threshold prices and a series of threshold loads.

In both the threshold price and threshold load approaches, we assumed that DR would participate in the top ten percent of hours. The threshold load approach assumed that DR would participate whenever the hourly system load exceeds the lowest load in the top ten percent of hours sorted from highest to lowest load (Load Stack). Similarly, the threshold price approach assumed that DR would participate whenever the hourly clearing price exceeds the lowest price in the top ten percent of hours sorted from highest to lowest price (Price Stack).

We used the hourly system load and day-ahead locational marginal price (DA LMP) data from the ISO New England's website. To provide a more granular analysis, we divided all hours of each year into three categories: summer, winter, and spring/fall. This allowed us to analyze the load-price variations between three groups of hours. The three categories also lessened the variations in prices due to seasonal or single-event fuel price swings.

Next, within each season of the year, we examined ten one-percent slices of the data (Load Stack or Price Stack, depending on the approach), from the first percent of highest load or price hours through the tenth percent of the highest load or price hours. We chose 1% slices to allow us to look at a limited number of hours in each slice. For the summer and winter periods, each 1% slice is about 22 hours. For the spring/fall periods, a 1% slice is about 44 hours.

[5] The issue of externalities has been contested in the FERC NOPR, RM10-17. We treat demand response offers as a day-ahead offer to reduce consumption without any consideration of the investments made by the DR provider, the opportunity costs, the system reliability benefits, the changes in air emissions, the energy bill savings to the retail customer, or any other externality that would need to be included for a comprehensive "net benefits" analysis.

Within each slice of data, we looked at the variation in load and price and identified the highest and the lowest load and price for each slice. We assume that the amount of DR responding in each hour is sufficient to reduce the hourly load to the level of the lowest load in the slice this hour belongs to. We further assume that this amount of DR is sufficient to bring the price down to the lowest price in this slice.

For each hour of the Load Stack and Price stack, we determined the amount of DR needed to reduce the price in that hour to the lowest price in the slice that hour belonged to. The amount of DR needed was calculated as the difference between the actual system load in that hour and the lowest load in the slice that hour belonged to. After determining resulting levels of System Load and Market-Clearing price for each hour in both the Load Stack and the Price Stack, we calculated potential net savings from DR participation using steps described in section 1 of Appendix A. These estimates represent the upper bound of potential net savings because, first of all, we assumed that DR would participate in all top ten percent of hours (with highest load or price); secondly, we assumed that a sufficient amount of DR would participate in every hour to bring the price down to the lowest price in the slice.

1. High Load Case

For the case of DR participation in the highest-load hours, we stacked the data on an hourly basis from highest to lowest by loads to create a so-called Load Stack. The higher loads generally correlated with the higher prices[6], but there were numerous variations. This is due to both the seasonal and daily variability of hourly system loads. For the top 10% of loads in 2009, summer peak loads ranged from 20,000 to 27,000 MW; winter peak loads ranged from 18,000 to 22,000 MW; and spring/fall peak loads rarely exceeded 19,000 MW. Within each season, the daily loads vary a great deal from daytime peaks to nighttime lows. Most of the time, seasonal peak loads and the prices associated with those loads can be anticipated, but there are significant exceptions. The loss of a major supply or transmission resource at a time when loads are well below seasonal peaks can raise prices in the day-ahead market for several days until additional supply or transmission resources become available. [7]

For the reasons described above, we analyzed hourly price-load data by season. As expected, the correlations between high loads and high prices were strongest for the summer period, weaker but consistent for the winter period, and most variable for the spring/fall periods. Tables 1 and 2 below show the correlation coefficient (r) and coefficient of determination (r^2) between high loads and high prices in the Load Stack for the three seasons and the years analyzed.[8]

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[6] All references to prices are to Day-Ahead LMP.

[7] A recent example occurred last winter. In early January 2010, the loss of significant generation resources caused higher than normal DA prices. *See*, ISO New England COO Report to NEPOOL Participants Committee, February 5, 2010, pages 14 and 19.

[8] Negligible value of the correlation coefficient for Spring/Fall 2008 indicated no correlation between load and price within that group of hours. Further in the analysis, we use correlation factors to adjust total net savings. We have excluded any correlation adjusted savings for Spring/Fall 2008 from our results as unreliable and not applicable (NA), even though we believe some savings would occur.

Table 1 Load-Price Correlation Factors in the top 10% of the Load Stack, 2006-2009

Year	Load-Price Correlation Factor		
	Winter	Summer	Spring/Fall
2006	0.45	0.86	0.24
2007	0.48	0.68	0.41
2008	0.39	0.79	-0.01
2009	0.50	0.80	0.40

Table 2 Load-Price Coefficient of Determination in the top 10% of the Load Stack, 2006-2009

Year	Coefficient of Determination (r2)		
	Winter	Summer	Spring/Fall
2006	0.20	0.74	0.06
2007	0.23	0.46	0.17
2008	0.15	0.63	0.00
2009	0.25	0.64	0.16

We used these seasonal correlation factors to adjust our estimated net savings for variations in the data. The analysis of one-percent slices of Load Stack shows that the lowest price in any slice of loads may or may not be the price of the lowest load in that slice. In some cases, the lowest loads in a slice can have some of the higher prices in that slice. Consequently, we later adjusted the savings by the correlation factor for that season for each year that we reviewed (from Table 1).

2. High Price Case

The analysis for the High Price Case is very similar to the High Load Case. We stacked the data on an hourly basis from highest to lowest based on price (Price Stack). For the top 10% of prices in 2009, day-ahead LMPs ranged from$83/MWh to $132/MWh in summer, from $44/MWh to $91/MWh in winter, and spring/fall DA LMPs were in the range of $47/MWh to $99/MWh. Similarly to the Load Stack, hours with the highest prices did not always correspond to the hours with the highest loads, with the same being true for the lowest price and lowest load hours.

We then again analyzed ten one-percent slices of price-load data for each season. However, when we reviewed the slices in the Price Stacks (one for each of the four years) we determined that the correlations and coefficients of determinations between load and price, shown in Tables 3 and 4, were generally lower in the data stacked by price than in the data stacked by load over the 10% of hours studied. In addition, the 1% slices showed extreme variability between prices and loads that would skew our analysis.

Table 3 Load-Price Correlation Factors in the top 10% of the Price Stack, 2006-2009

Year	Price-Load Correlation factor		
	Winter	Summer	Spring/Fall
2006	0.42	0.78	0.36
2007	0.24	0.67	0.33
2008	0.45	0.84	0.04
2009	0.38	0.60	0.35

Table 4 Load-Price Coefficient of Determination in the top 10% of the Price Stack, 2006-2009

Year	Load-Price Coefficient of Determination, R^2		
	Winter	Summer	Spring/Fall
2006	0.17	0.60	0.13
2007	0.06	0.45	0.11
2008	0.21	0.71	0.00
2009	0.15	0.36	0.12

We again used these correlation coefficients (from Table 3) to adjust calculated net savings for variations in the highest priced hours.

B. *Supply Stack Slope Cases*

Our second approach for estimating potential savings from DR participation used the slopes of the supply stack to estimate savings from different levels of DR participation. We used this supply stack slope approach to estimate the quantities of DR needed to achieve a threshold market price in the hours when DR participates. We also compared potential savings from different DR penetration levels.

Our supply stack slope approach requires a set of assumptions about the market supply stack. First, we fit all daily price-load data points into a simple linear model, assuming a linear positive relationship between market-clearing prices and system loads.[9] Second, we estimated only two supply models per day, one for daytime hours (8am – 7pm) and one for nighttime hours (1am – 7am and 8pm – 12am), assuming a constant slope of the supply curve within all hours of each period.[10] Figures 1 and 2 below illustrate a typical supply stack for a summer day, July 8, 2008,

[9] In reality, aggregated market supply stack usually has a "hockey stick" shape, with a long flat portion, representing base load, relatively short increasing portion, representing intermediate generating units, and almost vertical portion, representing peaking units.

[10] In fact, we would expect much higher variation in the slopes of the supply curve at different hours of the day: very high slopes during peak hours and very low slopes during off-peak hours. Even though in the ISO-NE Day-Ahead all bidders are required to submit the same set of price-quantity bids for all 24 hours of the following day, the "hockey-stick" shape of their offer curves allows for different slopes under different demand conditions. Given our simplified assumption of linear price-load relationship, the slope of our estimated supply curves is the same at any point. Therefore, to allow for variation in slopes at least during day and night time, we estimate "day" and "night" supply curves based on twelve price-load data points for

and linear approximations of this supply stack. Figure 1 provides a linear approximation of the supply stack for all load values; Figure 2 provides separate linear approximations for peak loads, above 25,000 MW, and off-peak loads, below 25,000 MW. As can be seen from the figures, the slope of the supply stack indeed varies significantly under different load conditions: high load slope of 0.1362 is about 6 times greater than the average slope of 0.0216, and low load slope of 0.0089 is almost 3 times smaller than the average slope. We use slopes of the supply stacks as a proxy for the price elasticity of supply, i.e. responsiveness of quantity to changes in price, and vice versa. Therefore, the more precise our calculated slopes are, the more accurate our resulting hourly loads and market-clearing prices are. An example of semi-daily slope calculations for two selected days is provided in Appendix B.

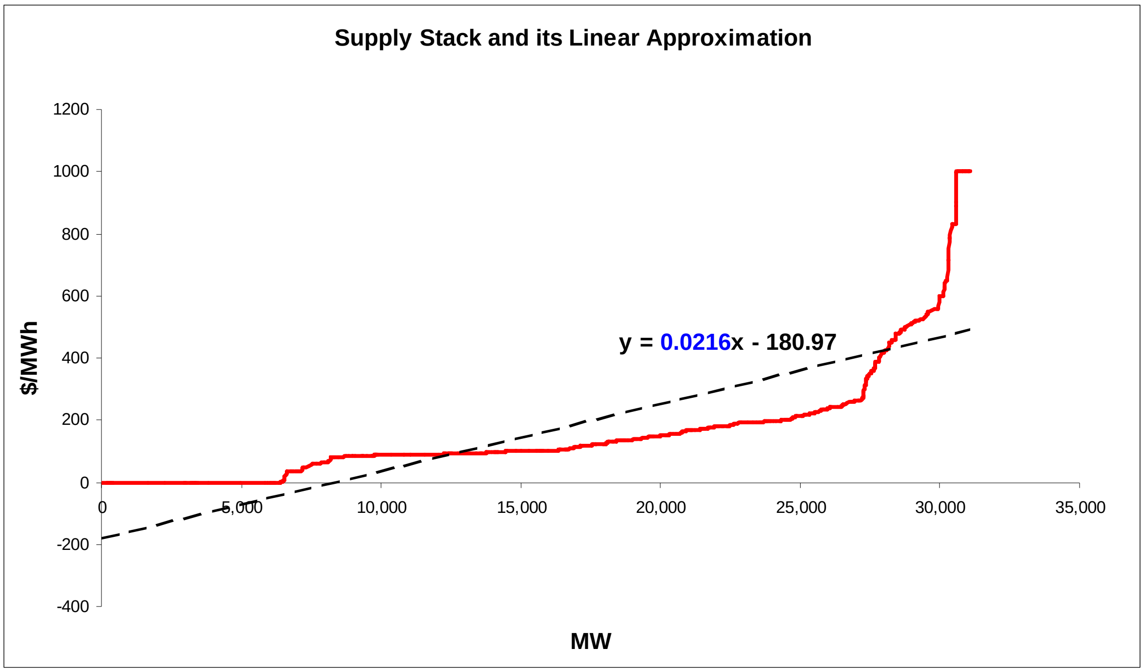

Figure 1 Supply Stack and Its Linear Approximation

each. Allowing for more variation in the slope would reduce the number of data points in each time period and significantly diminish fit of the supply curve.

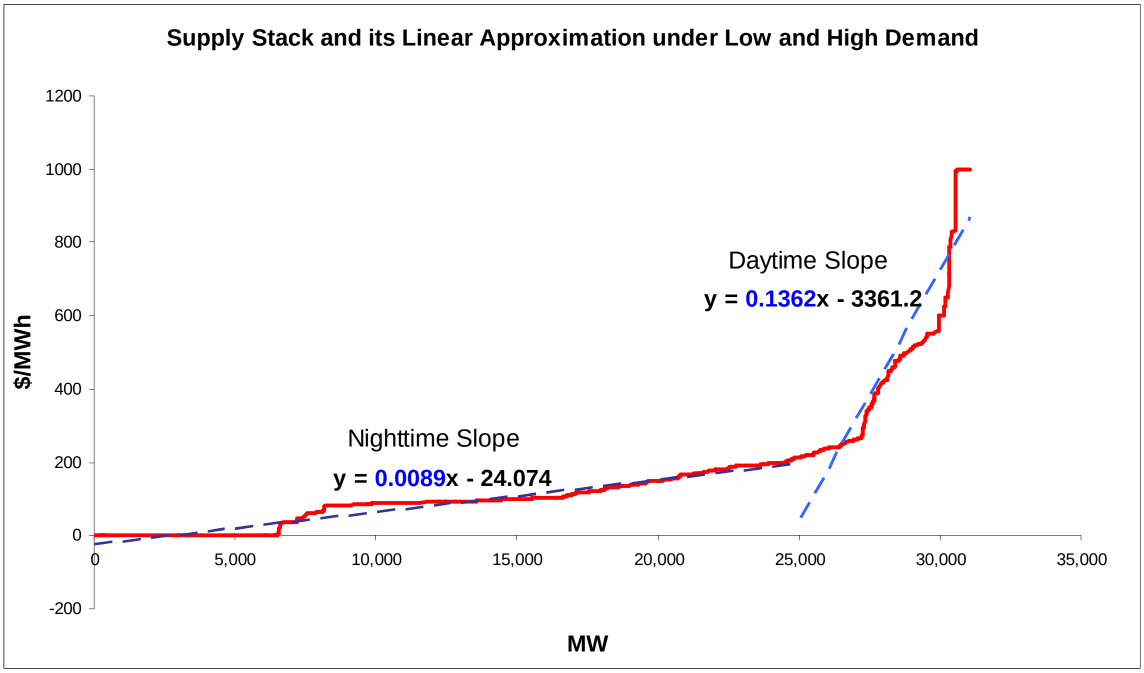

Figure 2 Supply Stack and Its Linear Approximation under Low and High Demand

Next, with our assumptions about DR penetration level, we use calculated semi-daily slopes of the supply curves to determine resulting market-clearing prices in each hour of the day when DR was allowed to participate. It is important to stress that we estimated potential savings from DR participation because we assumed that DR resources participate in all hours when they were allowed to participate. Our criteria for DR participation in a particular hour involved comparisons of actual market-clearing price in that hour and DR Participation Threshold Price ("threshold price") determined by ISO-NE on a monthly basis based on heat rate and forward reserves market fuel index.[11] A List of monthly threshold prices for 2006-2009 used in the analysis is provided in Appendix D. Table 5 below provides the number of hours of DR participation for each analyzed year. The analysis shows that while the number of DR participation hours was between 5,000 and 7,000 in 2006-2008, the number of hours that DR was allowed to participate dropped substantially, to 766 hours in 2009.

[11] ISO-NE uses a term Day-Ahead Load Response Minimum Offer Price for DR Participation Threshold Price. Data on the ISO-NE threshold price is only available starting from February 2008 (available at http://www.iso-ne.com/markets/othrmkts_data/dalr/dalr_mop/2010/day_ahead_load_response_minimum_offer_price.pdf). Threshold price for January 2006 – January 2008 is extrapolated by Synapse using data on Forward Reserves Market Threshold Price (available at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/threshold/2010/forward_reserve_market_threshold_price.pdf) and Average Monthly New England Natural Gas prices (collected from EIA Electric Power Monthly, Table 4.13.A. Average Cost of Natural Gas Delivered for Electricity Generation by State).

Table 5 Number of Hours of DR Participation, 2006-2009

Month	2006		2007		2008		2009	
	ISO-NE Threshold Price	# Hours of DR Partici-pation	ISO-NE Threshold Price	# Hours of DR Partici-pation	ISO-NE Threshold Price	# Hours of DR Partici-pation	ISO-NE Threshold Price	# Hours of DR Partici-pation
January	111	209	75	108	93	349	81	152
February	97	425	130	568	106	491	66	58
March	89	277	96	449	119	626	64	57
April	87	537	91	623	115	720	52	0
May	79	601	94	696	131	741	44	61
June	76	532	92	607	140	716	47	11
July	75	514	84	560	151	744	50	10
August	89	635	73	652	110	742	47	98
September	64	516	69	633	100	720	39	72
October	66	359	77	542	93	558	52	100
November	89	467	87	454	77	415	58	12
December	88	111	98	559	88	132	71	135
Annual	-	5,183	-	6,451	-	6,954	-	766

We developed two cases for our supply stack slope approach. In the first case, "Fixed DR Penetration Case", we analyzed three levels of DR penetration and used calculated semi-daily slopes to estimate changes in market-clearing price resulted from DR participation.

In the second case, "Computed DR Penetration Case", we assumed that in every hour that DR resources participated that the market-clearing price was reduced to the price threshold as a result of DR participation. Then we use the calculated semi-daily slopes to estimate the amount of DR needed to reduce the price to the price threshold level. Details for each case are provided in the following subsections.

After determining the resulting levels of System Load and the Market-Clearing price in both cases, we calculated the potential savings from DR participation using the steps described in section 2 of Appendix A. Both cases showed significant savings (Table 7 below), although "Computed DR Penetration" case showed greater potential savings in all years except for 2009.

1. Fixed DR Penetration Case

The "Fixed DR Penetration" case assumed three levels of DR participation: 5%, 10%, and 15% of hourly load. First, using the actual hourly market-clearing prices (Day-Ahead LMPs) and the monthly threshold price for DR participation, we identified the hours of DR participation. With hourly data on system load, we determined the amount of DR resources participating in the hour as a percentage of system load (for each of the three penetration assumptions) for all hours when the market-clearing prices were above the threshold price ("participation hours").

Then, using the slope of that day's supply stack, we calculated the change in price caused by DR participation.[12] Finally, with known changes in price and quantity, we calculated the hourly market-clearing prices and system loads that we then used to calculate DR participation and estimate potential savings, as described in Section 2 of Appendix A. Table E.1 in Appendix E shows calculation of resulting market-clearing prices and system loads for the ten highest priced hours in 2009 for all three levels of DR penetration.

2. Computed DR Penetration Case

The "Computed DR Penetration" case assumed that the participation of DR resources in the hours when it was allowed (based on the monthly threshold price) would bring the market-clearing price down to the threshold price level. Then we calculated the amount of DR (or change in system load) needed to induce such a price reduction.[13] Using the supply stack slope, with known changes in price and quantity, we calculated the hourly market-clearing prices and system loads. Table E.2 in Appendix E shows the calculation of the market-clearing prices and system loads for ten highest priced hours in 2009.

III. Discussion

A. Compare the Options

1. DR Resources Needed

For each of our cases we calculated or made an assumption about the amount of DR participating in each hour. In the High Load and High Price approaches we assumed that a sufficient amount of DR would participate in each hour of the top ten percent of hours to move the hourly clearing price down to the lowest price of the slice the hour belonged to. This amount of DR in each hour was equal to the difference between the actual system load in the hour and the lowest load in the slice the hour belonged to.

In the Fixed DR Penetration case of the Supply Stack Approach, we assumed a fixed DR participation level in each hour when DR was allowed to participate, 5%, 10%, or 15% of load, with a focus on the 10% DR penetration level.

Finally, in the Computed DR Penetration case of the Supply Stack Approach, the amount of DR needed was computed based on the known change in price (under assumption that the price would drop to the ISO-NE monthly threshold price as a result of DR participation) and the semi-daily slope of the supply stack.

[12] We calculated change in price as a product of change in quantity and a slope. This can also be described as the price elasticity of supply for that day.

[13] We calculated amount of DR needed as a ratio of change in price and a slope.

All four approaches produced different values of DR needed in each hour to achieve certain price/load levels. Figures 3-6 below show ten hours with the highest amount of DR needed in each of the approaches described above. While High Price and High Load approaches involved analysis of summer, winter and shoulder seasons separately, Figures 3 and 4 show top ten summer hours only; for the supply stack slope approach, Figures 5 and 6 show top ten hours throughout the entire year. [14]

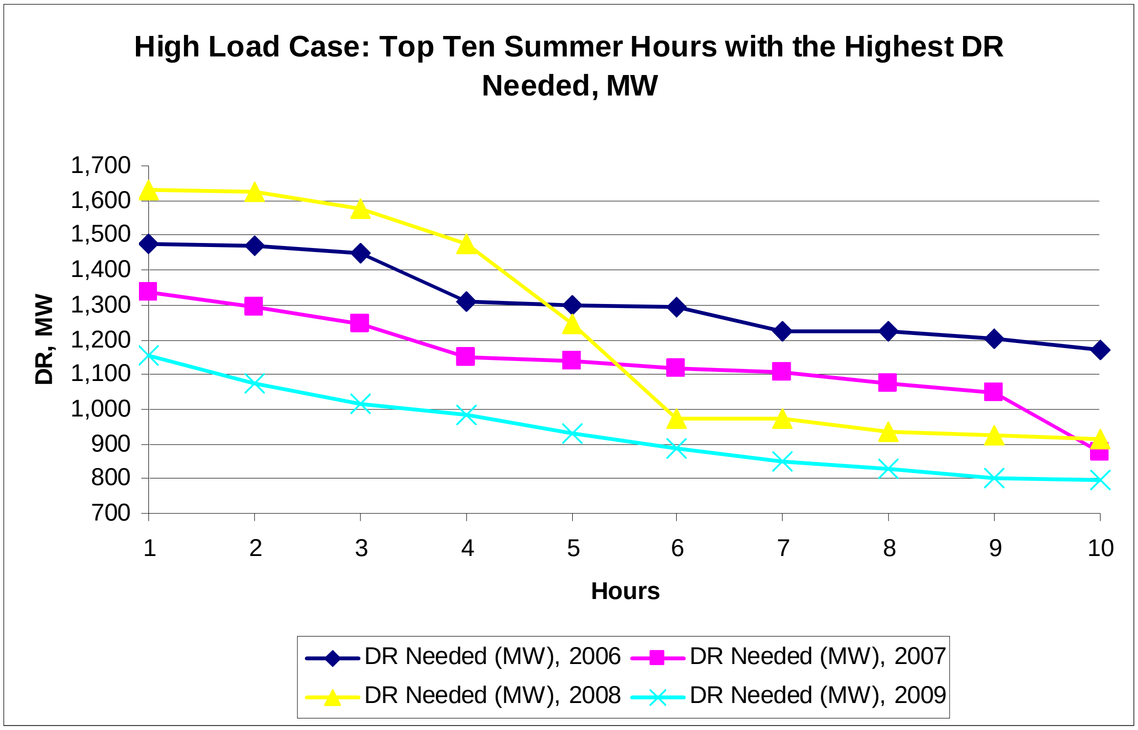

Figure 3 Highest Amounts of DR Needed, High Load Case

[14] Tables F.1.1 – F.1.8 and F.2.1 – F.2.4 in Appendix F provide more detailed data on top ten hours with the highest amounts of DR needed in each approach, year, and season.

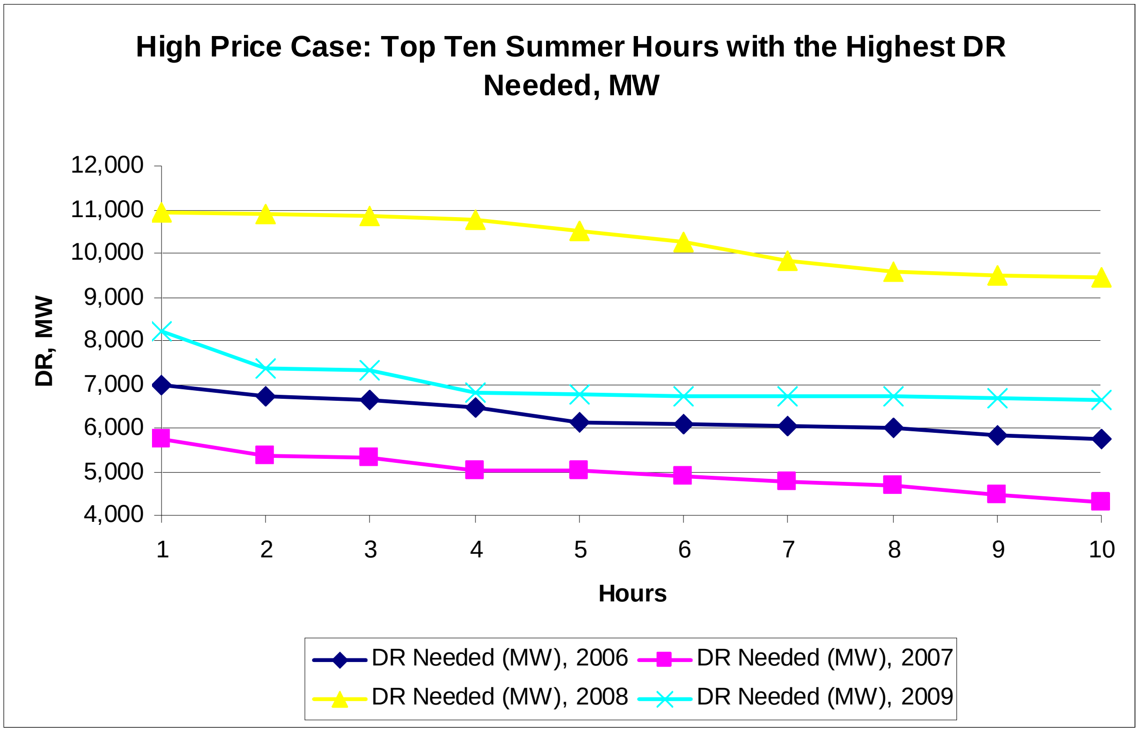

Figure 4 Highest Amounts of DR Needed, High Price Case

Figure 3 shows that the highest amount of DR needed in the summer hours never exceeded 1,700MW for any of the four years in the High Load case. Figure 4 shows that the DR quantities were 4,000 to over 10,000 MW in the High Price case.

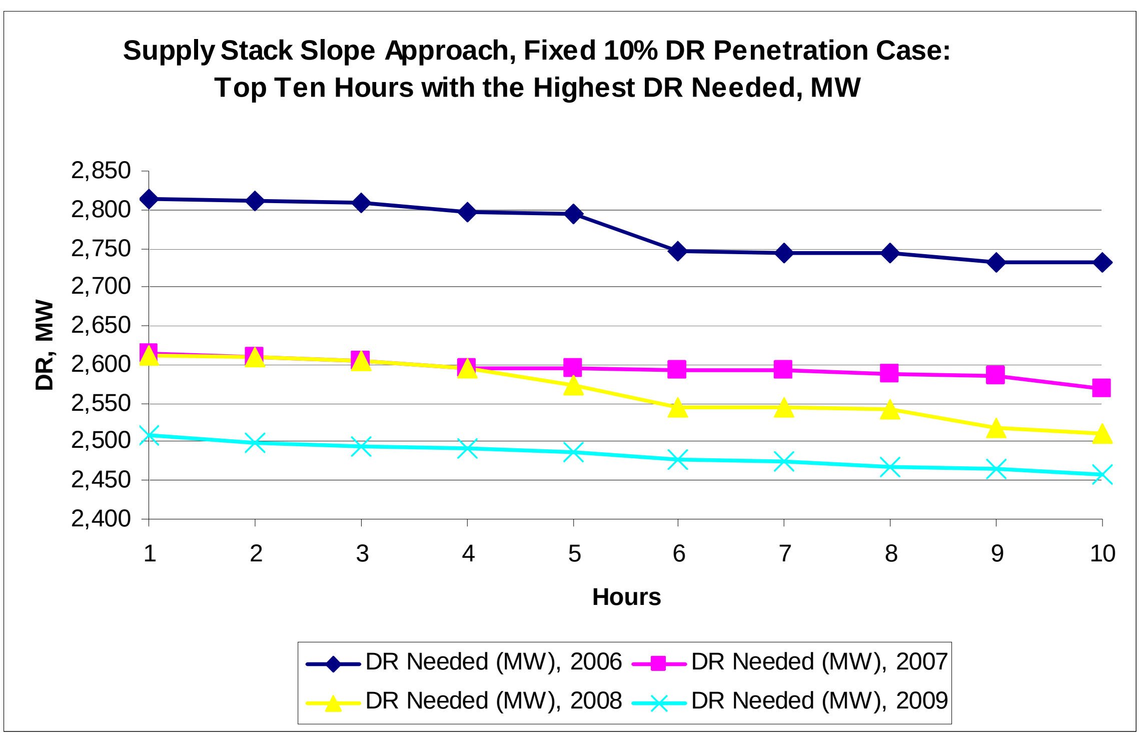

Figure 5 Highest Amounts of DR Needed, Fixed DR Penetration case of the Supply Stack approach

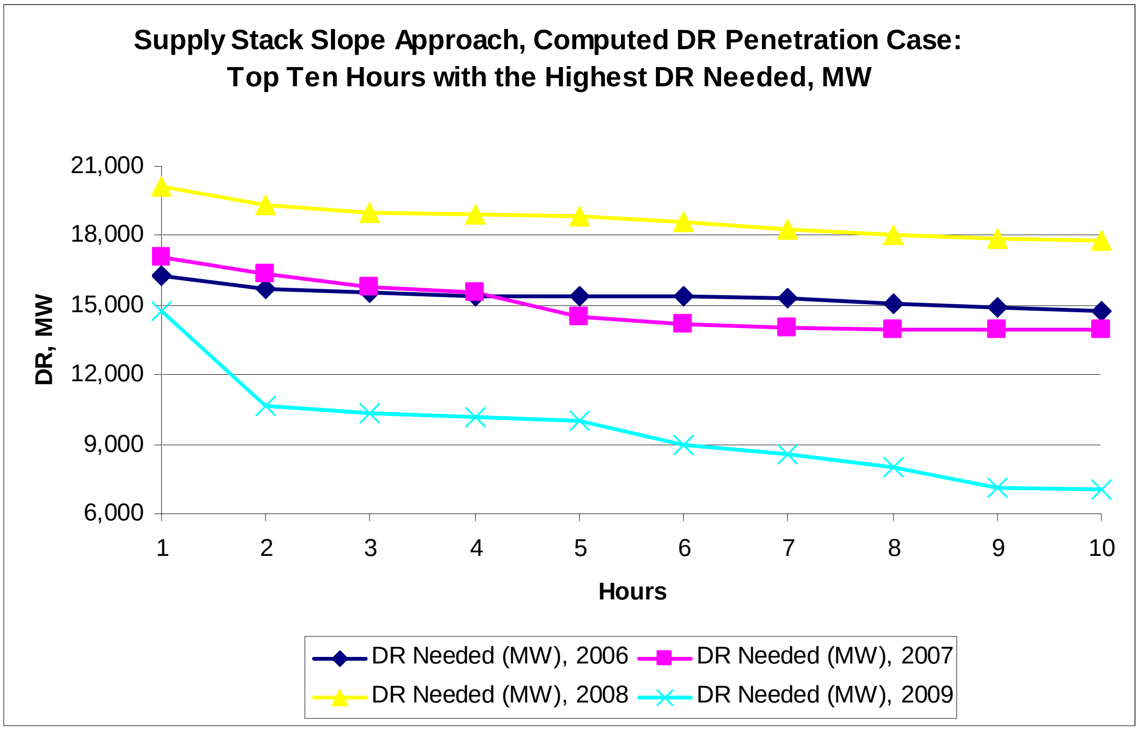

Figure 6 Highest Amounts of DR Needed, Fixed DR Penetration case of the Supply Stack approach

The highest amounts of DR needed in the Fixed 10% DR Penetration case, calculated as 10% of the hourly system load, exceeded the highest levels of DR in the High Load case but were significantly lower than the DR levels in the High Price case (Figure 5). Finally, in the Computed DR Penetration case, the highest amounts of DR needed reached unrealistically high levels (almost 21,000MW, Figure 6), which makes estimates of potential net savings in this case quite unreliable and highly overstated. However, these extremely high values of DR needed were the result of the assumption made for the Computed DR Penetration case that the hourly clearing price would necessarily drop to the level of ISO-NE monthly threshold price. Given that ISO-NE threshold prices were in some months as low as $40/MWh, and clearing prices in some hours were in the range of $100-300/MWh and up, the amount of DR needed to achieve such a substantial price reduction was indeed very high. Even in the hours when the clearing price is low, at the flat portion of the supply curve, a substantial amount of DR is needed for a very small change in price.

In both the High Price case and the Computed DR case, our assumption of a price reduction to a specific price level creates the unrealistically high levels of DR needed in some hours to achieve the assumed price.

2. Savings Impacts

Table 7 below summarizes potential net savings from DR participation in all four cases analyzed. Clearly, Computed DR Penetration Case of the Supply Stack Slope approach results in the highest level of savings. These substantial savings of 1 to 4 billions of dollars in 2006-2008 are the result of our assumption that in every hour, a sufficient amount of DR will participate to bring the price down to the ISO-NE monthly threshold price, which in some hours was substantially lower than the actual clearing price. On the other hand, the Fixed DR Penetration Case of the Supply Stack Slope approach does not assume that the clearing price would necessarily reduce to the threshold price, but rather calculates change in price due to change in system load using the supply stack slope, and therefore, produces more realistic estimates of net savings. After adjusting net savings using the seasonal correlation factors, the High Load Case and the High Price Case result in the lowest estimates of net savings from DR participation.

Table 7 Potential Net Savings from DR Participation in Four Cases

	Correlation Adjusted Net Savings , mln $		Net Savings , mln $	
Year	High Load Case	High Price Case	Fixed DR Penetration Case (10%)	Computed DR Penetration Case
2006	176	29	949	1,485
2007	207	18	1,168	2,307
2008	234	43	1,348	3,847
2009	137	15	162	145

B. Limitations of Analysis

Whether we base the analysis of DR participation on small slices of highest loads (or highest prices) or the slope of twelve hour bid stacks, the results demonstrate large variability and statistically unreliable savings estimates.

The seasonal variability is unmistakable in Tables 8 (High Load Case) and 9 (High Price Case) below, which show a summary of the analysis of the slices. In 2006, the savings followed an expected pattern: highest prices and largest savings in summer, then winter, then the shoulder months. However, in 2007, the highest prices were in winter, then shoulder months, and then summer. In 2009, the highest prices in the shoulder months provided more adjusted net savings than the summer months.

Table 8 Net Savings from High Load Case, 2006-2009

Season	Highest Price, $/MWH	Highest Load, $	Maximum DR, MW	DR Payment, mln $	Annual Net Savings, mln $	Correlation Adjusted Net Savings, mln $
2006						
Summer	217.43	28,130	1,478	6.93	**109.00**	**94.03**
Winter	136.65	20,702	902	1.56	**99.20**	**43.11**
Spring/Fall	108.47	19,598	1,068	2.75	**161.46**	**38.67**
Annual	**217.43**	**28,130**	**1,478**	**11.24**	**369.67**	**175.81**
2007						
Summer	135.00	26,145	1,336	4.30	**97.98**	**66.33**
Winter	207.35	21,640	1,066	2.01	**145.12**	**69.27**
Spring/Fall	150.00	22,570	2,231	6.04	**172.74**	**70.93**
Annual	**207.35**	**26,145**	**2,231**	**12.35**	**415.84**	**206.52**
2008						
Summer	367.19	26,111	1,633	7.29	**213.76**	**169.34**
Winter	185.77	21,782	1,701	1.97	**168.17**	**64.54**
Spring/Fall	136.43	22,204	3,003	6.51	**145.46**	**NA**
Annual	**367.19**	**26,111**	**3,003**	**15.77**	**527.39**	**233.88**
2009						
Summer	90.96	25,081	1,156	2.28	**41.79**	**33.53**
Winter	132.42	20,791	730	1.57	**107.74**	**53.97**
Spring/Fall	98.92	19,620	1,913	1.47	**123.13**	**49.50**
Annual	**132.42**	**25,081**	**1,913**	**5.32**	**272.66**	**137.00**

Table 8 also shows the price variability. In 2008, the highest prices in all three seasons exceeded $136/MWH; in 2009, none of the seasons exceeded $132/MWH. 2009 estimated adjusted net annual savings were almost 40% less than in 2008. Certainly, a lot of the total savings variability is affected by gas prices (with close to 50% of the energy coming from gas generation). But there are a number of additional factors.

Table 9 shows similar variability in the High Price Case. Although total savings are generally lower than in the High Load Case, the seasonal and yearly variations roughly follow the variations in the High Load Case.

Table 9 Net Savings from High Price Case 2006-2009

Season	Highest Price, $/MWH	Highest Load, $	Maximum DR, MW	DR Payment, mln $	Annual Net Savings, mln $	Correlation Adjusted Net Savings, mln $
2006						
Summer	217.43	28,130	2,970	64.67	**28.04**	**21.87**
Winter	136.65	20,702	4,210	39.92	**7.86**	**3.30**
Spring/Fall	109.06	19,598	4,624	80.60	**10.15**	**3.65**
Annual	**217.43**	**28,130**	**4,624**	**185.19**	**46.05**	**28.83**
2007						
Summer	135.00	26,145	3,051	52.72	**11.76**	**7.88**
Winter	207.35	21,640	5,406	87.39	**14.59**	**3.50**
Spring/Fall	150.00	22,570	12,009	137.45	**19.22**	**6.34**
Annual	**207.35**	**26,145**	**12,009**	**277.56**	**45.57**	**17.72**
2008						
Summer	367.19	26,111	9,729	92.40	**52.06**	**35.40**
Winter	185.77	21,782	5,085	76.35	**13.36**	**6.01**
Spring/Fall	199.21	19,727	5,866	113.92	**27.39**	**1.10**
Annual	**367.19**	**26,111**	**9,729**	**282.67**	**92.81**	**42.51**
2009						
Summer	90.96	25,081	2,252	34.30	**10.08**	**6.05**
Winter	132.42	20,791	4,367	45.58	**8.38**	**3.27**
Spring/Fall	98.92	19,620	6,785	69.78	**17.22**	**6.03**
Annual	**132.42**	**25,081**	**6,785**	**149.66**	**35.68**	**15.34**

The analysis based on the twelve-hour slope of the daily bid stack did not reduce the variability in savings on an annual basis. As shown in Table 7 above, the highest net savings from DR participation in the supply stack slope approach are achieved in 2008, followed by savings in 2007 and then 2006 (in all three years net savings are substantially higher in the Computed DR Participation case, as discussed above). Finally, 2009 net savings from DR participation are almost ten times lower than savings in 2006. Such a significant drop in the level of net savings is at least partially due to lower natural gas prices and much lower number of DR "participation" hours in 2009, compared to the other three years.

C. *Single Day Supply Stack*

To address the variability in the four cases we analyzed, we decided to look at a supply stack for a single day and determine the impact of a very modest quantity of DR participation.

New England's Day Ahead Load Response Programs currently use a threshold price that is adjusted monthly and indexed to the marginal fuel for generation units. We know that a DA offer from a demand response resource impacts the price paid by load because it reduces the number of billing units over which the energy costs can be allocated. By establishing a threshold price that is high enough (based on the supply stack slope), we can be assured that the introduction of a new DR supply offer will sufficiently reduce the clearing price to overcome any offset in the billing units.

However, the reality is that this supply curve is quite lumpy. There are a number of flat spots on the energy supply offer curve, even at relatively high prices. It is not the smooth curve we draw to represent hypothetical offer curves. It is inappropriate to assume that all Demand Response supply offers above a threshold will always result in overall lower costs to wholesale energy load purchasers.

The upper line in Figure 7, below, shows the full day-ahead energy market supply curve for 8 July 2008

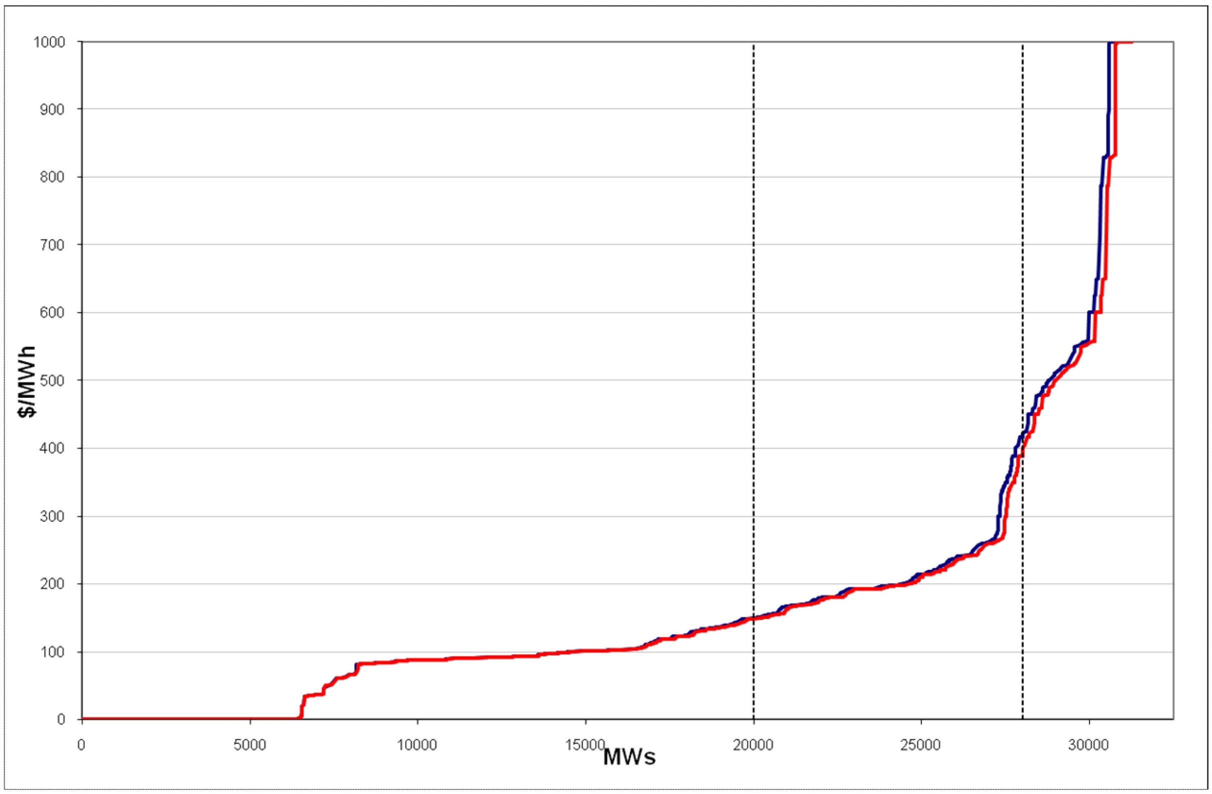

Figure 7 Supply Stack, July 8, 2008

The lower line shows the same supply curve, with the introduction of a sample amount of Demand Response offers in 20 MW blocks, ranging from $50/MWh up to $150/MWh. We have inserted 10 blocks, for a total of 200 MW of Demand Response, with offers centering around $115/MWh. Simply for reference purposes, we have drawn vertical demand lines at 20,000 MW and 28,000 MW. On a hot summer day, this might represent cleared demand during the early morning, and again in the early afternoon of an all-time peak load day for New England.

From this level, we can see that the day-ahead energy supply curve has several distinct inflection points, but otherwise looks relatively smooth between those points. If we zoom in, however, the reality of a lumpy supply curve is revealed.

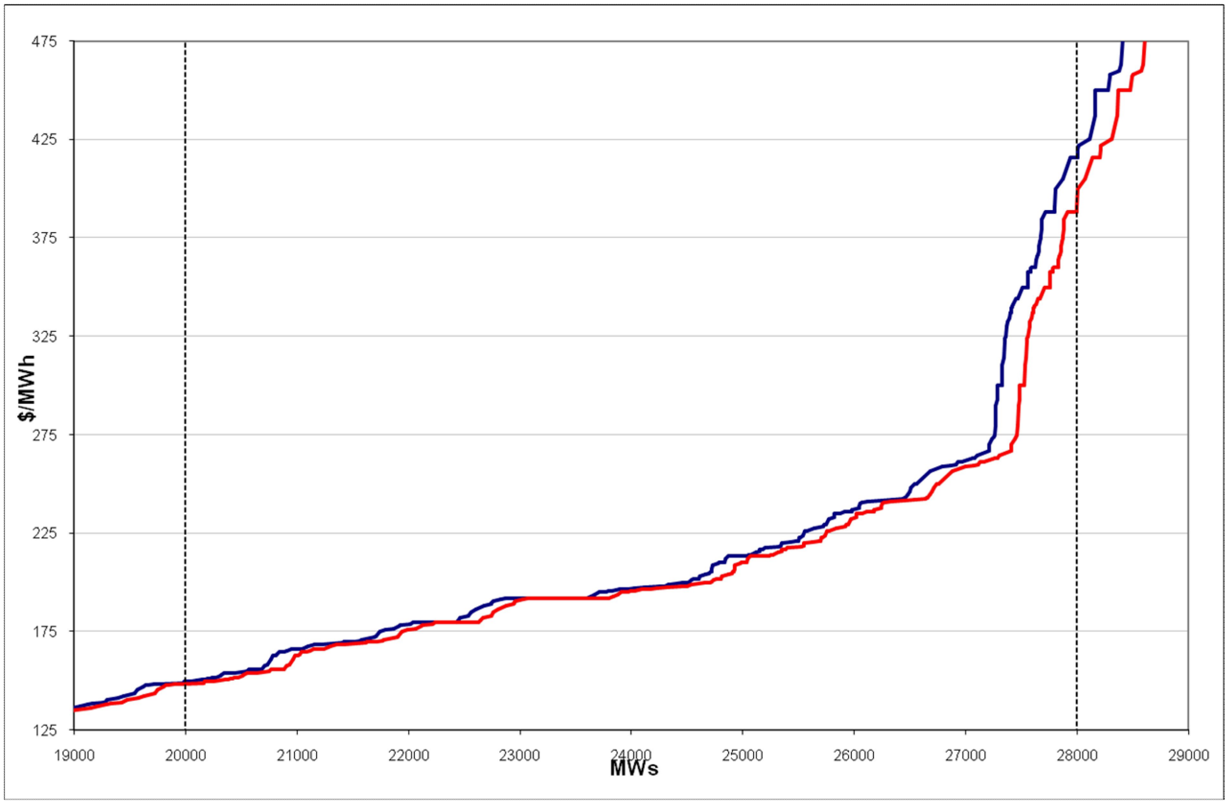

Figure 8 Enhanced Section of Supply Stack, July 8, 2008.

Figure 8 uses identical data from Figure 7, but focuses on the section of the curve between 20,000 MW of demand and 28,000 MW of demand. We can see clearly that there are certain portions of the curve at which the introduction of a small amount of new, lower cost supply would make no difference in the clearing price. Imagine if you will that the demand in one hour of this day was 23,300 MW. There is a long flat spot in the curve in this range, at a price of $192/MWh. With or without our sample 200 MW of Demand Response, the clearing price would still be $192/MWh. Hence, if we attempt to optimize just the energy market costs for this one hour, there would be no benefit to the remaining 23,100 MW of load to purchase 200 MW of demand response instead of generation, because of the effect on the number of billing units.

Many other demand levels would see a marked benefit from the introduction of our sample 200 MW of new, low cost supply. If this were an all-time peak hour of 28,000 MW, the price difference between these two curves is $16/MWh, for a one-hour wholesale energy cost reduction of $448,000. But we must be careful not to assume that these benefits would occur at any point on the day-ahead energy supply curve above a specified threshold price.

As mentioned in the Introduction, applying different quantities of DR participation to daily supply stacks will produce the most accurate estimates of potential savings. Yet, even this detailed and time-consuming analysis will not account for all the elements that ISO-NE evaluates to determine the final DA dispatch. The offer parameters of resources, limitations of the transmission system, daily outages, and the allocation of reserves can all affect the final set of resources that are selected for the DA market and set the DA LMP.

One would still need to include several assumptions about quantities of DR providing DA offers in order to estimate the range of potential savings. The 200 MW of DR used in the example help illustrate the issues related to a lumpy supply curve.

D. Other Variables

There are several other variables that can have a significant impact on DR participation and the annual savings from that participation.

Weather variances in heat and humidity or extreme cold can contribute to load forecast error that results in either an over-commitment or an under-commitment of DA resources. Having DR offers in the supply stack can provide greater flexibility to system operators in real time if they have resources available that can either increase generation or reduce loads to maintain a balanced system without dramatic price fluctuations or uplift charges.

Generation performance is another variable that can influence the extent and frequency of DR participation in the DA market. Extended outages, whether maintenance or unscheduled, can create locational and sometimes system-wide imbalances that cause the dispatch of out-of-merit resources for varying periods of time. DR offers in the DA market can provide system operators with flexible options for meeting short-term disruptions to efficient dispatch schedules.

Fuel price variations, particularly natural gas prices for New England, will also have direct impacts on the quantity and frequency of DR participation. The four-year analysis for 2006-2009 shows a direct correlation between high savings from DR participation and high gas prices. The steady increase in potential DR savings from 2006 through 2008 (in sync with natural gas prices) was dramatically reversed in 2009 when gas prices crashed and stayed down. The recession from 2008-2009 was also a contributing factor to the low potential DR savings in 2009.

The ISO's procedures for committing resources can also influence the quantity and frequency of DR participation. Long lead-time resources (mostly oil and coal fired resources) are often not included in DA commitment schedules due to lengthy minimum run times and (relatively) high operating costs. If loads exceed forecasted amounts (in any season) the unavailability of several thousand MW of resources can lead to price volatility and system resource adequacy concerns. The availability of DR offers in the DA market would make the consequences of inaccurate DA forecasts less severe in both reliability and economic terms.

IV. Recommendations

The approaches we developed and the cases we analyzed demonstrate two consistent themes about the potential savings from demand response participation in the DA energy market. First, demand response participation can provide substantial savings as reflected by reductions in the DA clearing price. Second, there is no single variable that can be used to accurately predict either the quantity of DR participation or the exact price impact of that participation. Only a day to day analysis of each supply stack with an assumed quantity of DR participation can provide a meaningful estimate of savings.

1. Avoid a Static Threshold

The use of a threshold offer price that limits DR participation will always be inaccurate: it will exclude DR participation in hours when DR can provide beneficial savings and it will include DR participation in hours when there are no beneficial savings. There are too many variables for each day (and sometimes each hour) that need to be considered before selecting the optimal set of resources that will provide the lowest daily production cost to meet anticipated day-ahead loads.

A static offer price threshold for demand response resources that is adjusted monthly (or more frequently) could be used while a dynamic threshold mechanism is developed and tested. However, adopting a static threshold through a stakeholder process may raise significant design issues (such as a four-hour minimum bid that is above the threshold in three hours but not in all four) and it may not be any easier or simpler to develop than a dynamic threshold.

2. Acknowledge Changes to the Resource Mix

ISO New England developed its own analysis of "net benefits" from DR participation in the wholesale energy market. The only documentation of that analysis is a power point presentation that summarizes the results without providing the details that support the summary.[15] The fundamental flaw in the ISO's analysis is the assumption that any reduction to producer revenues in the energy market will be recovered in the capacity market. That assumption leads to increased capacity costs that more than offset the benefits from lower energy market prices through DR participation.

The ISO's assumption about higher capacity market costs is flawed because the ISO assumes that all the resources participating in today's markets will continue to be needed with increased DR participation. It is likely that robust DR participation will reduce price volatility and increase the flexibility of system operators to respond to sudden changes in system conditions (either unanticipated higher loads or the loss of generation and transmission resources). The system operators will be able to dispatch DR to reduce loads instead of dispatching high-cost resources. Inflexible generation resources (slow to start with long minimum run times) may no longer be needed. Peaking generation with high operating costs may also no longer be needed. Market dynamics may expand the "out of merit" hours for these resources. The reduced price volatility from demand response participation in the energy markets will also reduce infra-marginal rents to all resources and create additional market pressure on inflexible and high-cost resources. [16]

[15] FERC Technical Conference, RM10-17, September 13, 2010. One of the critical details that is missing is whether the ISO based its analysis on day-ahead loads and prices or real-time loads and prices; we suspect that the ISO used real-time data, but we are not certain.

[16] It is important to remember that wholesale competitive markets produce just and reasonable rates because they provide an **opportunity** for resources to recover their costs and earn a profit; there is no guarantee that all costs will be recovered. ISO New England's analysis seems to assume that any costs not recovered in the wholesale energy market will be automatically recovered in the capacity market.

Over time, the attrition of some generation resources is likely if demand response resources increase the hours that they can clear in the energy markets. Dispatching fewer generation resources will lower the total dollars needed from all markets to support the remaining generation. The current trend of decreasing annual capacity factors may also be reversed as the remaining generation resources (the most efficient resources) are dispatched more frequently.

3. Develop a Dynamic Threshold

In order to realize the benefits of robust DR participation, a dynamic threshold that employs a simple benefit test is the best option. Our review of a single-day supply stack suggests that a threshold test similar to the one proposed by CDRI could be used to make decisions about the optimal quantity of demand response offers to clear in the DA energy market.[17] As long as demand response offers provide reductions to the overall cost of meeting the DA loads, they should be accepted; this will generally occur when the supply stack shows a positive slope at the clearing price. When demand response offers do not provide reductions to the overall cost of meeting the DA loads, they should be rejected; this will generally occur when the supply stack is flat at the clearing price. The optimization of the daily production cost of all resources is something that ISO/RTOs currently do when making decisions about generation offers in the DA supply stack. Expanding this process to include demand response resources is not a substantial change to existing practices.

4. Develop a Mechanism for Cost Allocation of DR benefits

DR participation in the DA energy market will reduce the billing units (the total load) in the DA energy market. The fewer billing units mean that the total DA energy market costs (the payments to generation and DR resources) will be assigned to a smaller quantity of total load. If both generation and DR are paid the full DA LMP, the remaining load will not provide sufficient compensation if it is charged the same LMP value that is being paid to generation and DR. Some call this the "missing money" issue.

There are two general approaches for addressing the "missing money": (1) charge the same LMP to load as is paid to supply resources, just as is done today, which would force a need to create a separate uplift cost and allocate that cost to day-ahead load in a post-market process, or (2) roll the cost into a DA price that is slightly higher than the LMP paid to supply resources and charge it to all day-ahead load. Uplift accounts are not a preferred approach; uplift charges are not transparent, difficult to predict, and subject to bitter disputes. Essentially, uplift charges raise the total hourly cost above the market clearing price that load is expected to pay. A roll-in approach is preferred because it is transparent, it is known as soon as the DA market clears, and over time it becomes predictable and can be hedged by LSEs.

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[17] The Consumer Demand Response Initiative (CDRI) has made several filings that explain the algorithm developed to calculate the maximum amount of DR for any hour. We have seen no evidence to date that the CDRI algorithm is not compatible with existing RTO market clearing mechanisms. In addition, the CDRI mechanism provides a way to make LSEs indifferent to the quantities of demand response offers in the DA energy market within their footprint.

An additional advantage to the dynamic benefits test recommended above is that it allows for an assignment of costs as part of the DA clearing mechanism. Because the entire quantity of generation and demand resources are optimized and selected together, the entire cost of all these resources is also known. The total cost can be assigned to all the loads that are being served through this optimal combination of resources. Our experience in the NEPOOL and PJM stakeholder processes has convinced us that the direct assignment of costs to beneficiaries through a market mechanism is preferable to an uplift charge process that collects a category of costs and then re-allocates them back to loads through a cost allocation formula. The assignment of the uplift costs is always disputed and many market participants will seek permanent or special case exemptions to the allocations. Assigning the costs as part of the day ahead clearing process will properly align the costs to the beneficiaries: the entire DA load.

APPENDIX A

1. Calculating net savings from demand response for analysis based on peak prices and peak load

We estimated the net savings from demand response for each slice in each season in the following steps:

- First, for each slice we determined the total cost to serve the actual load in each hour in the absence of any DR. This amount is reported in the "Total Cost" column as the product of the actual hourly system load and the day-ahead LMP from ISO data. This establishes a baseline cost for each hour.
- Second, for each slice we calculated the total cost to serve the minimum load in the slice at the minimum DA LMP for the slice based on the assumption that sufficient DR resources responded in each hour of the slice to reduce the DA LMP to the minimum price for that slice. This is reported in the "Modified Total Cost" column[18] as the product of the lowest load and the lowest price in the slice, and therefore has the same value for each hour within the slice.
- Third, for each slice we calculated the "Payment to DR" as the product of the difference between the hourly load in the absence of DR and the lowest load in the slice and the lowest price in the slice[19] This calculation follows from our assumption that DR participation in the day-ahead energy market results in the reduction of the market-clearing price to the lowest price in the slice, which is then paid to all dispatched generation and demand resources.
- Finally, we calculated net savings to all load by subtracting the "Modified Total Cost" and the "Payment to DR" from the baseline hourly "Total Cost".
- At this point in the analysis, we have a net savings value based on the minimum load in a slice and the minimum price in the slice. However, we know that there is not a one-to-one relationship between the minimum load in a slice and the minimum price. To correct for this lack of one-to-one correlation, we adjusted the net savings by the specific correlation factor between high loads and high prices for each season (column "Adjusted Net Savings"). In a similar manner, we calculate net savings and adjusted net savings for each hour in the top 10% Summer, Winter and Spring/Fall hours of all four analyzed years. For seasonal and annual net savings, we summed up these hourly savings across seasons and over all seasons, respectively.

[18] We assume that the amount of DR responding in each hour is sufficient to reduce hourly load to the level of the lowest load in the slice this hour belongs to. We further assume this amount of DR is sufficient to bring the price down to the lowest price in this slice.

[19] Once again, the difference between the actual hourly load and the lowest load in the slice represents maximum amount of DR needed to reduce the price to the lowest price in the slice.

Table A.1.1 provides an illustration of these calculations for the top 1% slice for Summer 2009.

Table A.1.1 Calculation of Net Savings in the 1% Slice of Summer 2009 Load Stack

Date	Hour	System Load 2009	DA LMP	Total Cost, mln$	Modified Total Cost, mln$	DR Payment, mln$	Net Savings, mln$	Correlation Coefficient	Adjusted Net Savings, mln$
8/18/2009	15	25,081	88.20	2.21	1.40	0.07	0.75	0.80	0.60
8/18/2009	14	24,998	88.63	2.22	1.40	0.06	0.76	0.80	0.61
8/21/2009	15	24,941	62.05	1.55	1.40	0.06	0.09	0.80	0.07
8/18/2009	16	24,909	89.58	2.23	1.40	0.06	0.78	0.80	0.62
8/21/2009	16	24,856	62.08	1.54	1.40	0.05	0.09	0.80	0.07
8/21/2009	14	24,776	61.80	1.53	1.40	0.05	0.09	0.80	0.07
8/18/2009	17	24,753	90.96	2.25	1.40	0.05	0.81	0.80	0.65
8/19/2009	15	24,676	70.07	1.73	1.40	0.04	0.29	0.80	0.23
8/19/2009	16	24,658	70.82	1.75	1.40	0.04	0.31	0.80	0.25
8/19/2009	17	24,581	70.82	1.74	1.40	0.04	0.31	0.80	0.25
8/18/2009	13	24,577	84.17	2.07	1.40	0.04	0.64	0.80	0.51
8/19/2009	14	24,475	68.61	1.68	1.40	0.03	0.25	0.80	0.20
8/17/2009	14	24,459	60.47	1.48	1.40	0.03	0.05	0.80	0.04
8/17/2009	15	24,442	62.00	1.52	1.40	0.03	0.09	0.80	0.07
8/21/2009	17	24,441	61.88	1.51	1.40	0.03	0.09	0.80	0.07
8/18/2009	18	24,398	85.68	2.09	1.40	0.03	0.67	0.80	0.54
8/17/2009	17	24,391	64.46	1.57	1.40	0.03	0.15	0.80	0.12
8/17/2009	16	24,390	61.70	1.50	1.40	0.03	0.08	0.80	0.07
8/21/2009	13	24,259	58.33	1.42	1.40	0.02	0.00	0.80	0.00
8/17/2009	18	24,221	60.49	1.47	1.40	0.02	0.05	0.80	0.04
8/19/2009	18	24,195	63.29	1.53	1.40	0.02	0.12	0.80	0.10
8/18/2009	12	23,925	80.08	1.92	1.40	0.00	0.52	0.80	0.42

Table A.1.2 uses the same calculations as Table A.1.1, but aggregates the results across slices to include all ten slices of hours for Summer 2009. Tables A.1.3 and A.1.4 use the same calculations as Table A.1.2 but for the Winter 2009 and Spring/Fall 2009 periods respectively.

Table A.1.2 Calculation of Net Savings in Ten Slices of Summer 2009 Supply Stack

2009 Load Stack	Total Cost, mln$	Lowest Load in %Slice, MW	Lowest Price in %Slice, $/MW	Modified Total Cost, mln$	DR Payment, mln$	Net Savings, mln$	Adjusted Net Savings, mln$
1st % of hrs	38.50	23925	58.33	30.70	0.82	6.98	5.60
2nd % of hrs	27.93	23019	44.36	22.46	0.38	5.09	4.08
3rd % of hrs	26.78	22471	39.13	19.34	0.19	7.24	5.81
4th % of hrs	23.85	22124	37.42	18.21	0.12	5.51	4.42
5th % of hrs	23.16	21717	39.49	18.87	0.15	4.14	3.32
6th % of hrs	22.40	21438	39.72	18.73	0.12	3.55	2.85
7th % of hrs	21.39	21086	41.66	19.33	0.15	1.92	1.54
8th % of hrs	19.97	20754	37.38	17.07	0.14	2.76	2.22
9th % of hrs	18.87	20469	38.3	17.25	0.11	1.51	1.21
10th % of hrs	18.70	20227	33.32	15.50	0.09	3.10	2.49

Table A.1.3 Calculation of Net Savings in Ten Slices of Winter 2009 Supply Stack

2009 Load Stack	Total Cost, mln$	Lowest Load in %Slice, MW	Lowest Price in %Slice, $/MW	Modified Total Cost, mln$	DR Payment, mln$	Net Savings, mln$	Adjusted Net Savings, mln$
1st % of hrs	46.20	20,061	83.00	34.97	0.56	10.67	5.35
2nd % of hrs	41.74	19,691	69.54	30.12	0.23	11.38	5.70
3rd % of hrs	36.67	19,382	65.01	26.46	0.18	10.02	5.02
4th % of hrs	36.65	19,213	58.74	24.83	0.12	11.71	5.87
5th % of hrs	37.44	19,032	54.85	22.97	0.08	14.40	7.21
6th % of hrs	32.11	18,889	56.64	22.47	0.09	9.54	4.78
7th % of hrs	34.55	18,760	62.76	25.90	0.09	8.56	4.29
8th % of hrs	30.83	18,622	50.74	19.84	0.08	10.91	5.47
9th % of hrs	31.57	18,538	54.56	22.25	0.04	9.28	4.65
10th % of hrs	33.40	18,382	52.11	22.03	0.10	11.27	5.65

Table A.1.4 Calculation of Net Savings in Ten Slices of Spring/Fall 2009 Supply Stack

2009 Load Stack	Total Cost, mln$	Lowest Load in %Slice, MW	Lowest Price in %Slice, $/MW	Modified Total Cost, mln$	DR Payment, mln$	Net Savings, mln$	Adjusted Net Savings, mln$
1st % of hrs	47.58	17,707	28.57	21.75	0.51	25.31	10.18
2nd % of hrs	42.43	17,351	28.52	21.77	0.22	20.44	8.22
3rd % of hrs	37.24	17,124	28.43	21.42	0.12	15.69	6.31
4th % of hrs	33.19	16,904	27.30	20.31	0.14	12.74	5.13
5th % of hrs	31.45	16,718	26.22	19.29	0.11	12.05	4.85
6th % of hrs	33.28	16,585	25.70	18.75	0.07	14.45	5.81
7th % of hrs	31.55	16,457	27.77	20.11	0.08	11.36	4.57
8th % of hrs	30.55	16,334	26.09	18.75	0.07	11.73	4.72
9th % of hrs	32.01	16,185	26.70	19.01	0.08	12.91	5.20
10th % of hrs	31.03	16,081	26.70	19.75	0.07	11.22	4.51

2. Calculating net savings from demand response for analysis based slope of the supply curve

We estimated the net savings from demand response for each hour that DR resources participate in using the following steps:

- First, we determined the total cost to serve the actual load in each hour in the absence of any DR. This amount is reported in the "Total Cost" column as the product of the actual hourly system load and the day-ahead LMP from ISO data. This establishes a baseline cost for each hour.
- Second, we calculated the total cost to serve reduced load in each hour at a reduced DA LMP for this hour based on the assumption that sufficient DR resources responded in each hour when they are allowed to reduce the DA LMP to the assumed level. This is reported in the "Modified Total Cost" column as the product of the system load after DR participation and the resulting DA LMP.
- Third, for each hour we calculated the "Payment to DR" as the product of the amount of DR participating in the hour and the resulting DA LMP.
- Fourth, we calculate net savings to all load by subtracting the "Modified Total Cost" and the "Payment to DR" from the baseline hourly "Total Cost".
- At this point in the analysis, we have a net savings value based on the hourly system load and DA LMP resulting from DR participation for each hour in our data set.[20] Finally, we calculate annual potential net savings from DR participation by summing up all hourly net savings.

[20] Net savings are equal to zero for the hours when there is no DR participation (i.e., DA LMP is below monthly threshold price)

Tables A.2.1 and A.2.2 below provide an illustration of these calculations for the ten top priced hours in 2009.

Table A.2.1 Net Savings Calculation, "Fixed DR Participation" Case

5% DR Participation										
Date	Hour	System Load	DA LMP	DR Needed, MW	**Resulting LMP, $/MWH**	**Load After DR Participation, MW**	**Actual Total Costs (TC), $**	**Modified Total Cost, $**	**Payment to DR, $**	**Net Savings, $**
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)= (c)*(d)**	**(i)=(f)*(g)**	**(j)=(e)*(f)**	**(k)=(h)-(i)-(j)**
1/14/2009	18	20,300	132.42	1,015	116.43	19,285	2,688,126	2,424,404	127,600	**136,122**
1/15/2009	18	20,630	130.29	1,032	117.01	19,599	2,687,883	2,400,264	126,330	**161,289**
1/14/2009	19	20,279	127.18	1,014	111.20	19,265	2,579,083	2,321,081	122,162	**135,840**
1/15/2009	19	20,702	125.96	1,035	112.63	19,667	2,607,624	2,322,946	122,260	**162,417**
1/16/2009	18	20,347	121.03	1,017	108.24	19,330	2,462,597	2,224,879	117,099	**120,619**
12/21/2009	18	20,270	120.63	1,014	112.13	19,257	2,445,170	2,169,116	114,164	**161,890**
1/14/2009	20	19,827	120.28	991	114.00	18,836	2,384,792	2,142,192	112,747	**129,852**
12/21/2009	19	20,232	119.99	1,012	111.51	19,220	2,427,638	2,153,036	113,318	**161,284**
10% DR Participation										
1/14/2009	18	20,300	132.42	2,030	100.43	18,270	2,688,126	2,174,294	241,588	**272,243**
1/15/2009	18	20,630	130.29	2,063	103.72	18,567	2,687,883	2,128,774	236,530	**322,579**
1/14/2009	19	20,279	127.18	2,028	95.23	18,251	2,579,083	2,076,662	230,740	**271,680**
1/15/2009	19	20,702	125.96	2,070	99.30	18,632	2,607,624	2,054,511	228,279	**324,834**
1/16/2009	18	20,347	121.03	2,035	95.46	18,312	2,462,597	1,999,223	222,136	**241,238**
12/21/2009	18	20,270	120.63	2,027	103.64	18,243	2,445,170	1,909,250	212,139	**323,781**
1/14/2009	20	19,827	120.28	1,983	107.71	17,844	2,384,792	1,912,578	212,509	**259,704**
12/21/2009	19	20,232	119.99	2,023	103.03	18,209	2,427,638	1,894,563	210,507	**322,568**
15% DR Participation										
1/14/2009	18	20,300	132.42	3,045	84.44	17,255	2,688,126	1,937,797	341,964	**408,365**
1/15/2009	18	20,630	130.29	3,095	90.44	17,536	2,687,883	1,873,413	330,602	**483,868**
1/14/2009	19	20,279	127.18	3,042	79.25	17,237	2,579,083	1,845,828	325,734	**407,521**
1/15/2009	19	20,702	125.96	3,105	85.97	17,597	2,607,624	1,802,317	318,056	**487,251**
1/16/2009	18	20,347	121.03	3,052	82.67	17,295	2,462,597	1,785,629	315,111	**361,858**
12/21/2009	18	20,270	120.63	3,041	95.14	17,230	2,445,170	1,665,574	293,925	**485,671**
1/14/2009	20	19,827	120.28	2,974	101.43	16,853	2,384,792	1,695,950	299,285	**389,557**
12/21/2009	19	20,232	119.99	3,035	94.55	17,197	2,427,638	1,652,218	291,568	**483,852**

Table A.2.2 Net Savings Calculation, "Computed DR Participation" Case

Date	Hour	System Load	DA LMP	DR Needed, MW	**Resulting LMP, $/MWH**	**Load After DR Participation, MW**	**Actual Total Costs (TC), $**	**Modified Total Cost, $**	**Payment to DR, $**	**Net Savings, $**
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)= (c)*(d)**	**(i)=(f)*(g)**	**(j)=(e)*(f)**	**(k)=(h)-(i)-(j)**
1/14/2009	18	20,300	132.42	7,783	81	17,037	2,688,126	1,013,848	630,452	**1,043,826**
1/15/2009	18	20,630	130.29	6,503	81	16,802	2,687,883	1,144,277	526,753	**1,016,853**
1/14/2009	19	20,279	127.18	6,990	81	17,348	2,579,083	1,076,394	566,205	**936,484**
1/15/2009	19	20,702	125.96	5,932	81	17,211	2,607,624	1,196,383	480,479	**930,762**
1/16/2009	18	20,347	121.03	6,870	81	17,162	2,462,597	1,091,659	556,448	**814,490**
12/21/2009	18	20,270	120.63	6,298	71	14,350	2,445,170	992,014	447,156	**1,006,000**
1/14/2009	20	19,827	120.28	5,946	81	13,630	2,384,792	1,124,382	481,605	**778,805**
12/21/2009	19	20,232	119.99	6,217	71	14,388	2,427,638	995,082	441,390	**991,166**

APPENDIX B

Seasonal savings estimates

The analysis of hourly price-load data for each slice showed that there was a lot of variation in both load and price values in each of the slices. For each slice we determined the highest and the lowest price and load values. Then we assumed that the maximum quantity of DR needed to reduce the price in a particular slice to the lowest price in that slice is equal to the difference between the highest hourly load and the lowest hourly load in that slice.[21]

Tables B.1, B.2, and B.3 below present the maximum and minimum loads, and maximum and minimum LMPs, in each of the ten slices of hours for the Summer, Winter and Spring/Fall of 2009 Load Stack respectively. The "Load Difference" column in each of those tables reports the maximum quantity of DR needed to reduce the price in each of the ten slices of hours to the minimum price. The "Price Difference" column in each table reports the resulting reduction in price.

Table B.1 Load and Price Characteristics in the top 10% of hours of the Load Stack for Summer 2009

2009 Load Stack	Max Load	Min Load	Load Difference	Max Price	Min Price	Price Difference
Summer						
1st % of hrs	25,081	23,925	1,156	90.96	58.33	32.63
2nd % of hrs	23,925	23,019	906	82.86	44.36	38.50
3rd % of hrs	23,019	22,471	548	72.11	39.13	32.98
4th % of hrs	22,471	22,124	347	57.04	37.42	19.62
5th % of hrs	22,124	21,717	407	54.78	39.49	15.29
6th % of hrs	21,717	21,438	279	55.23	39.72	15.51
7th % of hrs	21,438	21,086	352	50.00	41.66	8.34
8th % of hrs	21,086	20,754	332	52.18	37.38	14.80
9th % of hrs	20,754	20,469	285	47.10	38.30	8.80
10th % of hrs	20,469	20,233	236	46.54	33.32	13.22

Load variations (the difference between max and min loads in each slice) become small after the first few slices in summer 2009 (and for the other seasons, too). The price variations (difference between max and min price in each slice) are smaller in the summer period than any of the other seasons. This would suggest that savings might be greater in seasons other than summer,

[21] As an initial rough cut, we examined DR participation levels of 5%, 10%, 15%, and 20% of High Load hours (we did the same for High Price hours, too). The large variability in prices (for the High Load analysis) and the large variability in loads (for the High Price analysis) led to our decision to (1) segregate the analysis by season and (2) use 1% slices of High Loads and High Prices,

but we adjust the gross savings for the correlation factors for each season between high loads and high prices. The strong correlation for the summer months preserves much more of the summer gross savings and makes the summer net annual savings the highest in 2006 and 2008, almost equal (for all seasons) in 2007, and smallest in 2009 (details in Table 10).[22]

It is important to note that very low minimum prices occur in many of the slices for all the seasons. It is not anticipated that DR would actually be offering services in the DA market when prices were as low as $40 and $30 per MWh. Our methodology probably over-estimates the savings in low priced slices. Correspondingly, for some of the higher priced slices, the same "averaging" of all prices will probably under-estimate the savings in those slices.

Table B.2 Load and Price Characteristics in the top 10% of hours of the Load Stack for Winter 2009

2009 Load Stack	Max Load	Min Load	Load Difference	Max Price	Min Price	Price Difference
Winter						
1st % of hrs	20,791	20,061	730	132.42	83.00	49.42
2nd % of hrs	20,061	19,691	370	120.28	69.54	50.74
3rd % of hrs	19,691	19,382	309	118.17	65.01	53.16
4th % of hrs	19,382	19,213	169	105.76	58.74	47.02
5th % of hrs	19,213	19,032	181	112.31	54.85	57.46
6th % of hrs	19,032	18,889	143	112.16	56.64	55.52
7th % of hrs	18,889	18,760	129	111.75	62.76	48.99
8th % of hrs	18,760	18,622	138	98.69	50.74	47.95
9th % of hrs	18,622	18,538	84	115.38	54.56	60.82
10th % of hrs	18,538	18,393	145	99.42	59.00	40.42

[22] 2009 was a year of cool weather and economic recession. These two factors probably combined to produce very low DR participation and savings.

Table B.3 Load and Price Characteristics in the top 10% of hours of the Load Stack for Spring/Fall 2009

2009 Load Stack	Max Load	Min Load	Load Difference	Max Price	Min Price	Price Difference
Spring/Fall						
1st % of hrs	19,620	17,707	1,913	97.59	28.57	69.02
2nd % of hrs	17,707	17,351	356	98.5	28.52	69.98
3rd % of hrs	17,351	17,124	227	89.08	28.43	60.65
4th % of hrs	17,124	16,904	220	89.08	27.30	61.78
5th % of hrs	16,904	16,718	186	72.16	26.22	45.94
6th % of hrs	16,718	16,585	133	91.16	25.70	65.46
7th % of hrs	17,127	17,026	101	71.27	27.77	43.50
8th % of hrs	16,457	16,334	123	70.65	26.09	44.56
9th % of hrs	16,334	16,185	149	98.92	26.70	72.22
0th % of hrs	16,185	16,086	99	54.91	26.70	28.21

APPENDIX C

Daily versus Semi-daily Supply Stack Slopes

In this section we provide an example of calculating daily and semi-daily slopes of the supply stack for one randomly selected winter day and one summer day, and discuss the differences between the two.

In the two tables below Daily R-squared and Daily slopes are calculated based on a single supply stack per day (24 price-quantity data points), and Day/Night R-squared and slopes are based on "day" and "night" supply stacks (12 price-quantity data points each). "NO DR" indicates that no DR Participation is allowed in the hour since DA LMP in this hour is below ISO-NE determined threshold price.

Clearly, day slope of the supply curve (8am – 7pm, in bold) is greater and night slope (1am – 7am, and 8pm – 12am) is smaller than the average daily slope both for winter and summer day, which is consistent with the fact that load curve intersects supply stack at a much steeper portion where supply reaches its capacity during peak hours, and at a flatter portion during off-peak hours.

Table C.1 Daily vs. Semi-Daily Supply Stack Slopes, December 21, 2009

Date	Hour	System Load	DA LMP	Threshold Price	Daily R2	Daily Slope	Day/Night R2	Day/Night Slope
Winter Day								
12/21/2009	1	13,576	65.35	71	No DR	No DR	No DR	No DR
12/21/2009	2	13,114	70.14	71	No DR	No DR	No DR	No DR
12/21/2009	3	12,932	65.05	71	No DR	No DR	No DR	No DR
12/21/2009	4	12,930	68.85	71	No DR	No DR	No DR	No DR
12/21/2009	5	13,299	71.00	71	No DR	No DR	No DR	No DR
12/21/2009	6	14,393	75.39	71	0.79	0.0079	0.82	0.0070
12/21/2009	7	16,424	104.66	71	0.79	0.0079	0.82	0.0070
12/21/2009	8	17,652	116.95	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	9	17,985	117.46	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	10	18,039	117.09	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	11	18,006	117.07	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	12	17,865	111.10	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	13	17,629	100.64	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	14	17,483	88.13	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	15	17,335	85.00	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	16	17,471	86.14	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	17	18,900	112.16	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	18	20,270	120.63	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	19	20,232	119.99	71	0.79	0.0079	**0.38**	**0.0084**
12/21/2009	20	19,834	118.62	71	0.79	0.0079	0.82	0.0070
12/21/2009	21	19,233	105.53	71	0.79	0.0079	0.82	0.0070
12/21/2009	22	18,105	99.87	71	0.79	0.0079	0.82	0.0070

12/21/2009	23	16,512	77.01	71	0.79	0.0079	0.82	0.0070
12/21/2009	24	14,914	63.59	71	No DR	No DR	No DR	No DR

Table C.1 Daily vs. Semi-Daily Supply Stack Slopes, August 18, 2009

Date	Hour	System Load	DA LMP	Threshold Price	Daily R2	Daily Slope	Day/Night R2	Day/Night Slope
Summer Day								
8/18/2009	1	16,113	34.95	47	No DR	No DR	No DR	No DR
8/18/2009	2	15,105	31.80	47	No DR	No DR	No DR	No DR
8/18/2009	3	14,504	28.67	47	No DR	No DR	No DR	No DR
8/18/2009	4	14,161	27.29	47	No DR	No DR	No DR	No DR
8/18/2009	5	14,191	27.80	47	No DR	No DR	No DR	No DR
8/18/2009	6	14,902	30.84	47	No DR	No DR	No DR	No DR
8/18/2009	7	16,245	34.03	47	No DR	No DR	No DR	No DR
8/18/2009	8	18,246	37.59	47	No DR	No DR	**No DR**	**No DR**
8/18/2009	9	19,960	42.16	47	No DR	No DR	**No DR**	**No DR**
8/18/2009	10	21,479	52.91	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	11	22,829	67.91	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	12	23,925	80.08	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	13	24,577	84.17	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	14	24,998	88.63	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	15	25,081	88.20	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	16	24,909	89.58	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	17	24,753	90.96	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	18	24,398	85.68	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	19	23,527	82.86	47	0.92	0.0058	**0.96**	**0.0085**
8/18/2009	20	22,865	72.11	47	0.92	0.0058	0.89	0.0043
8/18/2009	21	22,832	68.60	47	0.92	0.0058	0.89	0.0043
8/18/2009	22	21,475	50.18	47	0.92	0.0058	0.89	0.0043
8/18/2009	23	19,512	39.09	47	No DR	No DR	No DR	No DR
8/18/2009	24	17,615	37.68	47	No DR	No DR	No DR	No DR

APPENDIX D

ISO New England Threshold Prices for DR Participation

Table D.1 Monthly DR Participation Threshold Prices, 2006-2009

Year	Month	Threshold Price, $/MWH	Year	Month	Threshold Price, $/MWH
2009	1	81	2007	1	75
2009	2	66	2007	2	130
2009	3	64	2007	3	96
2009	4	52	2007	4	91
2009	5	44	2007	5	94
2009	6	47	2007	6	92
2009	7	50	2007	7	84
2009	8	47	2007	8	73
2009	9	39	2007	9	69
2009	10	52	2007	10	77
2009	11	58	2007	11	87
2009	12	71	2007	12	98
2008	1	93	2006	1	111
2008	2	106	2006	2	97
2008	3	119	2006	3	89
2008	4	115	2006	4	87
2008	5	131	2006	5	79
2008	6	140	2006	6	76
2008	7	151	2006	7	75
2008	8	110	2006	8	89
2008	9	100	2006	9	64
2008	10	93	2006	10	66
2008	11	77	2006	11	89
2008	12	88	2006	12	88

We determined whether DR resources participate in the market in a particular hour based on the relationship between the actual DA LMP in that hour and the DR Participation Threshold Price ("threshold price") defined by ISO-NE on a monthly basis based on heat rate and forward reserves market fuel index. ISO-NE refers to this threshold price as the Day-Ahead Load Response Minimum Offer Price. Data on the ISO-NE threshold price is only available starting from February 2008[23]. Threshold prices for January 2006 – January 2008 are extrapolated by Synapse using data on Forward Reserves Market Threshold Price and Average Monthly New England Natural Gas prices.[24]

[23] Data on the ISO-NE threshold price is available at http://www.iso-ne.com/markets/othrmkts_data/dalr/dalr_mop/2010/day_ahead_load_response_minimum_offer_price.pdf.

[24] Forward Reserves Market Threshold Price data are available at http://www.iso-ne.com/markets/othrmkts_data/res_mkt/threshold/2010/forward_reserve_market_threshold_price.pdf.

Average Monthly New England Natural Gas prices collected from EIA Electric Power Monthly, Table 4.13.A. Average Cost of Natural Gas Delivered for Electricity Generation by State.

APPENDIX E

Calculating Resulting Hourly System Loads and Market-Clearing Prices after DR Participation

Table E.1 Calculating Resulting Hourly System Loads and Market-Clearing Prices after DR Participation in the Fixed DR Participation Case: Ten highest priced hours

5% DR Participation								
Date	Hour	System Load	DA LMP	**Semi-Daily Slope**	**Price Reduction, $/MWH**	**DR Needed, MW**	**Resulting LMP, $/MWH**	**Load After DR Participation, MW**
(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)=(g)*(e)**	**(g)=(c)*10%**	**(h)=(d)-(f)**	**(i)=(c)-(g)**
1/14/2009	18	20,300	132.42	0.02	15.99	1,015	116.43	19,285
1/15/2009	18	20,630	130.29	0.01	13.28	1,032	117.01	19,599
1/14/2009	19	20,279	127.18	0.02	15.98	1,014	111.20	19,265
1/15/2009	19	20,702	125.96	0.01	13.33	1,035	112.63	19,667
1/16/2009	18	20,347	121.03	0.01	12.79	1,017	108.24	19,330
12/21/2009	18	20,270	120.63	0.01	8.50	1,014	112.13	19,257
1/14/2009	20	19,827	120.28	0.01	6.28	991	114.00	18,836
12/21/2009	19	20,232	119.99	0.01	8.48	1,012	111.51	19,220
10% DR Participation								
1/14/2009	18	20,300	132.42	0.02	31.99	2,030	100.43	18,270
1/15/2009	18	20,630	130.29	0.01	26.57	2,063	103.72	18,567
1/14/2009	19	20,279	127.18	0.02	31.95	2,028	95.23	18,251
1/15/2009	19	20,702	125.96	0.01	26.66	2,070	99.30	18,632
1/16/2009	18	20,347	121.03	0.01	25.57	2,035	95.46	18,312
12/21/2009	18	20,270	120.63	0.01	16.99	2,027	103.64	18,243
1/14/2009	20	19,827	120.28	0.01	12.57	1,983	107.71	17,844
12/21/2009	19	20,232	119.99	0.01	16.96	2,023	103.03	18,209
15% DR Participation								
1/14/2009	18	20,300	132.42	0.02	47.98	3,045	84.44	17,255
1/15/2009	18	20,630	130.29	0.01	39.85	3,095	90.44	17,536
1/14/2009	19	20,279	127.18	0.02	47.93	3,042	79.25	17,237
1/15/2009	19	20,702	125.96	0.01	39.99	3,105	85.97	17,597
1/16/2009	18	20,347	121.03	0.01	38.36	3,052	82.67	17,295
12/21/2009	18	20,270	120.63	0.01	25.49	3,041	95.14	17,230
1/14/2009	20	19,827	120.28	0.01	18.85	2,974	101.43	16,853
12/21/2009	19	20,232	119.99	0.01	25.44	3,035	94.55	17,197

Table E.2 Calculating Resulting Hourly System Loads and Market-Clearing Prices after DR Participation in the Computed DR Participation Case: Ten highest priced hours

Date	Hour	System Load	DA LMP	Semi-Daily Slope	Price Reduction, $/MWH	DR Needed, MW	Resulting LMP, $/MWH	Load After DR Participation, MW
(a)	(b)	(c)	(d)	(e)	(f)=(d)-(h)	(g)=(f)/(e)	(h)=Threshold Price	(i)= (c)-(g)
1/14/2009	18	20,300	132.42	0.02	51.42	3,263	81	17,037
1/15/2009	18	20,630	130.29	0.01	49.29	3,828	81	16,802
1/14/2009	19	20,279	127.18	0.02	46.18	2,931	81	17,348
1/15/2009	19	20,702	125.96	0.01	44.96	3,491	81	17,211
1/16/2009	18	20,347	121.03	0.01	40.03	3,185	81	17,162
12/21/2009	18	20,270	120.63	0.01	49.63	5,920	71	14,350
1/14/2009	20	19,827	120.28	0.01	39.28	6,197	81	13,630
12/21/2009	19	20,232	119.99	0.01	48.99	5,844	71	14,388

APPENDIX F.

Maximum DR Participation in the Top Ten Hours

1. Calculating Maximum DR Participation (MW) for analysis based on peak prices and peak load

a. Hours with the Highest DR Participation in the Load Stack

Table F.1.1 Ten Hours with the Highest DR Participation (Load Stack), 2006

2006				
Date	**Hour**	**System Load**	**DA LMP**	**DR Needed, MW**
Summer				
8/2/2006	15	28,130	206.09	**1,478**
8/2/2006	14	28,122	205.87	**1,470**
8/2/2006	16	28,101	205.89	**1,449**
8/2/2006	13	27,961	217.11	**1,309**
8/2/2006	17	27,951	217.43	**1,299**
8/3/2006	16	26,611	164.06	**1,293**
7/17/2006	18	26,544	125.54	**1,226**
7/17/2006	15	26,543	136.00	**1,225**
8/3/2006	12	26,519	129.39	**1,201**
8/1/2006	19	26,488	138.15	**1,170**
Winter				
12/8/2006	18	20,702	104.55	**902**
1/16/2006	18	20,559	127.59	**759**
1/16/2006	19	20,491	107.28	**691**
2/27/2006	19	20,469	116.66	**669**
12/8/2006	19	20,425	92.14	**625**
12/5/2006	18	20,271	94.50	**471**
1/3/2006	18	20,258	136.65	**458**
2/27/2006	20	20,,238	103.00	**438**
12/5/2006	19	20,211	92.02	**411**
12/20/2006	19	19,795	73.54	**347**
Spring/Fall				
3/2/2006	19	19,598	94.05	**1,068**
5/30/2006	15	19,411	66.82	**881**
5/30/2006	16	19,373	66.86	**843**
5/30/2006	14	19,360	67.82	**830**
5/30/2006	17	19,304	67.53	**774**
3/1/2006	19	19,231	90.54	**701**
3/3/2006	19	19,204	94.71	**674**
9/19/2006	20	19,,168	54.53	**638**
3/2/2006	20	19,164	84.00	**634**
9/18/2006	20	19,140	56.85	**610**

Table F.1.2 Ten Hours with the Highest DR Participation (Load Stack), 2007

2007				
Date	**Hour**	**System Load**	**DA LMP**	**DR Needed, MW**
Summer				
8/3/2007	15	26,145	135.00	**1,336**
8/3/2007	16	26,102	132.26	**1,293**
6/27/2007	15	26,055	117.91	**1,246**
8/3/2007	14	25,960	134.92	**1,151**
6/27/2007	16	25,947	118.00	**1,138**
8/3/2007	17	25,927	128.13	**1,118**
8/2/2007	17	25,914	124.28	**1,105**
8/2/2007	16	25,882	122.31	**1,073**
6/27/2007	14	25,854	114.00	**1,045**
8/2/2007	18	25,685	119.98	**876**
Winter				
2/5/2007	19	21,640	137.48	**1,066**
2/5/2007	18	21,235	142.76	**661**
2/5/2007	20	21,187	122.00	**613**
12/17/2007	18	21,164	207.35	**590**
12/17/2007	19	21,136	199.92	**562**
12/13/2007	18	21,109	166.59	**535**
1/26/2007	19	21,034	140.48	**460**
1/26/2007	18	21,027	146.46	**453**
2/15/2007	19	20,950	130.70	**376**
12/13/2007	17	20,308	148.30	**281**
Spring/Fall				
9/7/2007	16	22,570	97.39	**2,231**
9/7/2007	17	22,545	95.74	**2,206**
9/7/2007	15	22,301	95.22	**1,962**
9/26/2007	16	22,189	91.07	**1,850**
9/26/2007	17	22,131	91.07	**1,792**
9/7/2007	18	22,081	91.87	**1,742**
9/26/2007	15	22,018	90.73	**1,679**
9/8/2007	16	21,867	97.53	**1,528**
9/26/2007	20	21,861	82.08	**1,522**
9/8/2007	15	21,843	96.06	**1,504**

Table F.1.3 Ten Hours with the Highest DR Participation (Load Stack), 2008

2008				
Date	Hour	System Load	DA LMP	DR Needed, MW
Summer				
6/10/2008	17	26,111	315.41	**1,633**
6/10/2008	15	26,103	365.96	**1,625**
6/10/2008	16	26,055	363.56	**1,577**
6/10/2008	14	25,955	367.19	**1,477**
6/10/2008	18	25,721	310.42	**1,243**
6/9/2008	17	25,453	222.99	**975**
6/10/2008	13	25,452	309.23	**974**
6/9/2008	16	25,412	222.96	**934**
7/18/2008	15	24,445	237.37	**926**
7/8/2008	18	24,433	189.00	**914**
Winter				
1/3/2008	19	21,782	184.27	**1,701**
1/3/2008	18	21,707	185.77	**1,626**
1/3/2008	20	21,341	147.00	**1,260**
12/8/2008	18	21,026	98.73	**945**
12/8/2008	19	21,004	89.41	**923**
1/2/2008	19	20,690	124.84	**609**
1/3/2008	21	20,630	140.82	**549**
1/2/2008	18	20,580	134.54	**499**
12/8/2008	20	20,572	87.34	**491**
12/19/2008	18	20,569	92.62	**488**
Spring/Fall				
9/5/2008	15	22,204	82.11	**3,003**
9/5/2008	16	22,162	76.95	**2,961**
9/5/2008	14	21,989	81.88	**2,788**
9/5/2008	17	21,908	75.34	**2,707**
9/4/2008	17	21,663	84.27	**2,462**
9/5/2008	13	21,604	83.84	**2,403**
9/4/2008	16	21,510	85.70	**2,309**
9/4/2008	18	21,469	82.08	**2,268**
9/5/2008	18	21,245	78.32	**2,044**
9/4/2008	15	21,220	83.60	**2,019**

Table F.1.4 Ten Hours with the Highest DR Participation (Load Stack), 2009

2009				
Date	Hour	System Load	DA LMP	DR Needed, MW
Summer				
8/18/2009	15	25,081	88.20	**1,156**
8/18/2009	14	24,998	88.63	**1,073**
8/21/2009	15	24,941	62.05	**1,016**
8/18/2009	16	24,909	89.58	**984**
8/21/2009	16	24,856	62.08	**931**
8/19/2009	13	23,905	67.20	**886**
8/21/2009	14	24,776	61.80	**851**
8/18/2009	17	24,753	90.96	**828**
8/17/2009	13	23,819	56.77	**800**
8/20/2009	15	23,814	47.79	**795**
Winter				
12/17/2009	18	20,791	102.79	**730**
12/29/2009	18	20,761	95.00	**700**
12/17/2009	19	20,749	99.90	**688**
1/15/2009	19	20,702	125.96	**641**
12/29/2009	19	20,684	87.19	**623**
1/15/2009	18	20,630	130.29	**569**
12/17/2009	20	20,437	88.78	**376**
12/18/2009	18	20,040	74.92	**349**
1/28/2009	18	19,995	89.31	**304**
2/5/2009	20	19,995	86.28	**304**
Spring/Fall				
3/2/2009	19	19,620	85.56	**1,913**
3/3/2009	19	19,210	97.59	**1,503**
3/2/2009	20	19,063	79.23	**1,356**
3/3/2009	20	18,953	96.71	**1,246**
3/2/2009	18	18,888	77.29	**1,181**
3/4/2009	19	18,865	91.31	**1,158**
3/4/2009	20	18,610	84.26	**903**
3/3/2009	21	18,307	95.39	**600**
3/2/2009	13	18,262	62.19	**555**
9/23/2009	20	18,215	47.84	**508**

b. Hours with the Highest DR Participation in the Price Stack

Table F.1.5 Ten Hours with the Highest DR Participation (Price Stack), 2006

2006				
Date	Hour	System Load	DA LMP	DR Needed, MW
Summer				
7/28/2006	12	24,185	94.76	**6,972**
7/14/2006	17	23,939	93.38	**6,726**
7/14/2006	16	23,855	93.38	**6,642**
7/14/2006	15	23,701	92.38	**6,488**
7/17/2006	22	24,243	90.58	**6,148**
7/18/2006	22	23,316	94.22	**6,103**
7/26/2006	19	23,243	94.22	**6,030**
7/17/2006	21	25,075	98.93	**5,995**
7/25/2006	16	23,034	93.53	**5,821**
7/25/2006	17	22,941	94.57	**5,728**
Winter				
12/5/2006	18	20,271	94.50	**4,423**
12/19/2006	18	19,873	87.91	**4,252**
12/8/2006	18	20,702	104.55	**4,210**
12/8/2006	19	20,425	92.14	**4,015**
1/16/2006	19	20,491	107.28	**3,999**
2/27/2006	20	20,238	103.00	**3,835**
12/11/2006	19	19,661	93.66	**3,813**
12/5/2006	19	20,211	92.02	**3,801**
2/7/2006	19	19,342	87.80	**3,721**
12/4/2006	18	20,078	100.90	**3,675**
Spring/Fall				
3/6/2006	20	18,443	74.74	**5,892**
3/16/2006	20	17,906	74.37	**5,355**
11/27/2006	20	17,719	74.34	**5,168**
5/31/2006	15	18,657	76.32	**5,091**
5/31/2006	14	18,450	77.37	**4,983**
3/3/2006	21	18,271	76.95	**4,804**
5/31/2006	18	18,761	75.41	**4,763**
5/31/2006	16	18,876	78.37	**4,708**
3/1/2006	20	18,975	79.77	**4,702**
11/21/2006	20	18,156	77.02	**4,689**

Table F.1.6 Ten Hours with the Highest DR Participation (Price Stack), 2007

2007				
Date	**Hour**	**System Load**	**DA LMP**	**DR Needed, MW**
Summer				
6/28/2007	19	22,805	83.98	**5,752**
8/24/2007	17	22,395	83.50	**5,342**
7/30/2007	13	22,352	84.40	**5,299**
8/3/2007	22	22,092	83.78	**5,039**
8/16/2007	16	22,062	84.47	**5,009**
8/29/2007	16	21,934	84.13	**4,881**
8/16/2007	15	21,799	84.01	**4,746**
8/29/2007	15	21,735	83.91	**4,682**
7/10/2007	20	21,532	84.29	**4,479**
7/27/2007	15	24,332	86.03	**4,305**
Winter				
2/14/2007	18	20,449	113.72	**7,281**
1/25/2007	20	20,107	115.45	**6,939**
12/21/2007	18	19,964	113.69	**6,796**
2/15/2007	19	20,950	130.70	**6,663**
12/7/2007	19	19,605	114.80	**6,437**
12/12/2007	19	19,596	115.27	**6,428**
12/7/2007	17	19,534	114.52	**6,366**
2/5/2007	10	19,365	114.97	**6,197**
1/25/2007	19	20,379	128.91	**6,092**
2/6/2007	20	20,373	130.13	**6,086**
Spring/Fall				
9/7/2007	16	22,570	97.39	**12,009**
9/7/2007	17	22,545	95.74	**11,984**
9/7/2007	15	22,301	95.22	**11,740**
9/8/2007	16	21,867	97.53	**11,306**
9/8/2007	15	21,843	96.06	**11,282**
9/7/2007	14	21,790	96.08	**11,229**
9/8/2007	17	21,670	99.21	**11,109**
9/8/2007	14	21,583	95.87	**11,022**
9/8/2007	18	21,124	97.97	**10,563**
5/25/2007	16	20,463	98.83	**9,902**

Table F.1.7 Ten Hours with the Highest DR Participation (Price Stack), 2008

2008				
Date	Hour	System Load	DA LMP	DR Needed, MW
Summer				
6/10/2008	17	26,111	315.41	**10,915**
6/10/2008	15	26,103	365.96	**10,907**
6/10/2008	16	26,055	363.56	**10,859**
6/10/2008	14	25,955	367.19	**10,759**
6/10/2008	18	25,721	310.42	**10,525**
6/10/2008	13	25,452	309.23	**10,256**
6/10/2008	19	25,012	269.64	**9,816**
6/10/2008	12	24,777	292.28	**9,581**
6/9/2008	17	25,453	222.99	**9,489**
6/9/2008	16	25,412	222.96	**9,448**
Winter				
12/22/2008	20	20,176	111.69	**6,770**
2/11/2008	19	20,498	108.12	**6,768**
1/4/2008	19	19,882	110.59	**6,476**
12/23/2008	18	19,829	105.00	**6,432**
1/17/2008	18	19,559	109.90	**6,153**
12/21/2008	18	19,914	113.61	**6,123**
12/31/2008	18	19,753	107.24	**6,023**
1/15/2008	18	19,343	105.05	**5,946**
1/4/2008	11	19,313	109.49	**5,907**
1/16/2008	19	19,615	107.90	**5,885**
Spring/Fall				
5/27/2008	13	17,726	105.39	**6,853**
9/15/2008	11	19,518	107.18	**5,889**
9/15/2008	12	19,727	103.43	**5,866**
4/1/2008	20	16,709	104.83	**5,836**
3/1/2008	18	16,455	105.00	**5,582**
4/9/2008	21	16,236	105.24	**5,363**
4/7/2008	9	16,187	105.31	**5,314**
3/10/2008	20	18,219	136.43	**5,299**
4/1/2008	9	16,092	105.01	**5,219**
4/8/2008	9	16,045	105.27	**5,172**

Table F.1.8 Ten Hours with the Highest DR Participation (Price Stack), 2009

2009				
Date	Hour	System Load	DA LMP	DR Needed, MW
Summer				
8/20/2009	18	23,403	44.36	**8,221**
8/20/2009	16	23,732	48.39	**7,359**
8/20/2009	14	23,651	51.54	**7,302**
8/17/2009	21	23,138	49.62	**6,789**
8/5/2009	14	23,135	50.29	**6,786**
8/11/2009	17	23,069	50.53	**6,720**
8/17/2009	20	23,068	49.85	**6,719**
8/20/2009	13	23,087	49.24	**6,714**
8/11/2009	14	23,019	50.20	**6,670**
8/5/2009	15	22,996	51.69	**6,647**
Winter				
12/29/2009	19	20,684	87.19	**5,539**
2/5/2009	20	19,995	86.28	**4,850**
12/17/2009	17	19,462	88.40	**4,683**
12/17/2009	20	20,437	88.78	**4,478**
1/5/2009	18	19,166	87.53	**4,387**
12/17/2009	18	20,791	102.79	**4,367**
12/29/2009	20	20,198	83.00	**4,351**
12/17/2009	19	20,749	99.90	**4,325**
2/4/2009	18	19,071	88.53	**4,292**
12/29/2009	18	20,761	95.00	**4,205**
Spring/Fall				
3/2/2009	13	18,262	62.19	**8,621**
3/2/2009	21	18,185	66.03	**8,544**
3/2/2009	12	18,158	69.93	**8,517**
3/5/2009	19	18,040	64.27	**8,399**
3/2/2009	11	17,881	70.31	**8,240**
3/5/2009	20	17,793	65.51	**8,152**
3/1/2009	19	17,719	65.31	**8,078**
11/5/2009	18	17,440	64.59	**7,799**
3/5/2009	9	17,299	60.61	**7,658**
11/4/2009	18	17,297	63.96	**7,656**

2. Calculating Maximum DR Participation (MW) for the supply stack slope approach

Table F.2.1 Ten Hours with the Highest DR Participation, 2006

2006						
Date	Hour	System Load	DA LMP	**DR Needed, MW**		
Fixed DR Penetration						
				5% of Load	10% of Load	15% of Load
8/2/2006	15	28,130	206.09	1,407	2,813	4,220
8/2/2006	14	28,122	205.87	1,406	2,812	4,218
8/2/2006	16	28,101	205.89	1,405	2,810	4,215
8/2/2006	13	27,961	217.11	1,398	2,796	4,194
8/2/2006	17	27,951	217.43	1,398	2,795	4,193
8/1/2006	17	27,467	149.20	1,373	2,747	4,120
8/2/2006	12	27,436	176.47	1,372	2,744	4,115
8/2/2006	18	27,432	198.77	1,372	2,743	4,115
7/18/2006	15	27,329	146.00	1,366	2,733	4,099
8/1/2006	16	27,319	159.03	1,366	2,732	4,098
Computed DR Penetration						
6/1/2006	15	20,756	105.24	16,254		
8/1/2006	21	25,955	137.45	15,723		
6/1/2006	14	20,580	102.58	15,512		
6/1/2006	18	20,242	102.19	15,403		
5/18/2006	15	16,263	62.71	15,382		
5/18/2006	12	16,312	62.69	15,365		
6/1/2006	13	20,118	101.81	15,297		
6/1/2006	12	19,679	101.07	15,091		
6/1/2006	16	20,818	100.54	14,943		
5/18/2006	18	15,707	61.98	14,781		

Table F.2.2 Ten Hours with the Highest DR Participation, 2007

2007						
Date	Hour	System Load	DA LMP	DR Needed, MW		
Fixed DR Penetration						
				5% of Load	10% of Load	15% of Load
8/3/2007	15	26,145	135.00	1,307	2,615	3,922
8/3/2007	16	26,102	132.26	1,305	2,610	3,915
6/27/2007	15	26,055	117.91	1,303	2,606	3,908
8/3/2007	14	25,960	134.92	1,298	2,596	3,894
6/27/2007	16	25,947	118.00	1,297	2,595	3,892
8/3/2007	17	25,927	128.13	1,296	2,593	3,889
8/2/2007	17	25,914	124.28	1,296	2,591	3,887
8/2/2007	16	25,882	122.31	1,294	2,588	3,882
6/27/2007	14	25,854	114.00	1,293	2,585	3,878
8/2/2007	18	25,685	119.98	1,284	2,569	3,853
Computed DR Penetration						
12/13/2007	20	20,169	132.06	17,037		
12/18/2007	7	17,382	161.88	16,319		
12/13/2007	21	19,333	127.65	15,806		
12/13/2007	7	16,431	126.68	15,536		
8/10/2007	15	16,855	69.13	14,493		
8/10/2007	16	16,538	68.68	14,198		
5/14/2007	18	15,693	84.91	14,009		
8/2/2007	21	24,112	97.55	13,966		
8/10/2007	14	17,162	68.27	13,930		
8/10/2007	17	16,323	68.26	13,923		

Table F.2.3 Ten Hours with the Highest DR Participation, 2008

2008						
Date	Hour	System Load	DA LMP	**DR Needed, MW**		
Fixed DR Penetration						
				5% of Load	10% of Load	15% of Load
6/10/2008	17	26,111	315.41	1,306	2,611	3,917
6/10/2008	15	26,103	365.96	1,305	2,610	3,915
6/10/2008	16	26,055	363.56	1,303	2,606	3,908
6/10/2008	14	25,955	367.19	1,298	2,596	3,893
6/10/2008	18	25,721	310.42	1,286	2,572	3,858
6/9/2008	17	25,453	222.99	1,273	2,545	3,818
6/10/2008	13	25,452	309.23	1,273	2,545	3,818
6/9/2008	16	25,412	222.96	1,271	2,541	3,812
6/9/2008	15	25,179	222.70	1,259	2,518	3,777
6/9/2008	18	25,110	223.03	1,256	2,511	3,767
Computed DR Penetration						
7/7/2008	21	21,649	125.97			20,091
6/30/2008	22	19,595	118.90			19,321
6/30/2008	20	20,477	117.82			19,031
8/14/2008	12	18,921	80.56			18,919
7/7/2008	20	21,843	121.21			18,832
7/7/2008	22	21,031	120.28			18,586
9/6/2008	18	19,434	76.95			18,233
9/6/2008	20	19,331	70.91			18,041
9/6/2008	16	19,497	76.23			17,887
9/6/2008	17	19,403	75.96			17,758

Table F.2.4 Ten Hours with the Highest DR Participation, 2009

2009						
Date	Hour	System Load	DA LMP	**DR Needed, MW**		
Fixed DR Penetration						
				5% of Load	10% of Load	15% of Load
8/18/2009	15	24,753	90.96	1,254	2,508	3,762
8/18/2009	14	24,909	89.58	1,250	2,500	3,750
8/21/2009	15	24,998	88.63	1,247	2,494	3,741
8/18/2009	16	25,081	88.20	1,245	2,491	3,736
8/21/2009	16	24,658	70.82	1,243	2,486	3,728
8/21/2009	14	24,581	70.82	1,239	2,478	3,716
8/18/2009	17	24,676	70.07	1,238	2,475	3,713
8/19/2009	15	24,856	62.08	1,234	2,468	3,701
8/19/2009	16	24,941	62.05	1,233	2,466	3,699
8/19/2009	17	24,776	61.80	1,229	2,458	3,687
Computed DR Penetration						
12/29/2009	18	16,303	98.92	14,781		
2/5/2009	7	20,761	95.00	10,675		
12/29/2009	9	17,503	91.17	10,328		
12/29/2009	8	16,661	91.16	10,211		
12/29/2009	19	17,470	88.00	9,971		
12/18/2009	7	16,882	87.77	8,980		
2/5/2009	20	16,016	87.58	8,601		
3/2/2009	19	20,684	87.19	7,990		
3/3/2009	7	19,995	86.28	7,153		
3/4/2009	7	19,620	85.56	7,064		