Quantifying Demand Response Benefits In PJM

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1.0 EXECUTIVE SUMMARY

There is widespread recognition of the need to institute demand response (DR) in today's electricity markets. During critical peaks in the demand for electricity, such as during summer heat waves, wholesale electricity prices can rise to their highest levels. Most end-use customers are on fixed retail rates that do not reflect spot market signals, causing inefficient outcomes in which they continue to use energy in low-value applications even when the wholesale price of electricity is very high. The recent Energy Policy Act of 2005 includes provisions that call upon states and utilities to evaluate and implement demand response programs to help address this situation.[1] California has initiated comprehensive regulatory proceedings about demand response, advanced metering and dynamic pricing. Other states, including Hawaii, Idaho, Illinois, Missouri and New Jersey, are conducting pilot programs with a variety of innovative demand response rates and technologies.

For these reasons, the PJM Interconnection, LLC (PJM) and the Mid-Atlantic Distributed Resources Initiative (MADRI) are interested in developing DR resources as a meaningful contributor to the power markets within the PJM region.[2] In order to inform the development of prudent policies and investments, they have sought to quantify the benefits of demand response. PJM, working with the MADRI state commissions, thus issued a request for proposal (RFP) for this study quantifying the impact of demand curtailment on wholesale prices and customer costs in the MADRI states and in the broader PJM region.

In accordance with the RFP, this study uses a simulation-based approach to quantify the market impact of curtailing 3% of load in the BGE, Delmarva, PECO, PEPCO, and PSEG zones during the top twenty 5-hour price blocks in 2005 and under a variety of alternative market conditions. We performed simulations using the Dayzer model developed by Cambridge Energy Solutions (CES), and using data provided by CES, PJM, and public sources. By comparing simulations with and without curtailments, we obtained the following results:

- Curtailing 3% of each selected zone's super-peak load, which reduces PJM's peak load by 0.9%, yields an energy market price reduction of $8-$25 per megawatt-hour, or 5-8% on average, during the 133-152 hours in which curtailment occurs in at least one zone. The range depends on market conditions.
- Assuming all loads (i.e., customers or their retail providers) are exposed to spot prices, the estimated price reductions could benefit non-curtailed loads in MADRI states by $57-$182 million per year. The potential benefits to the entire PJM system amount to $65-$203 million per year.
- The market impact in each zone would be substantially smaller if it curtailed its load in isolation from the other zones. By the same token, the market impact would be larger if

[1] Section 1252 of Energy Policy Act of 2005. See Public Law No: 109-58.

[2] MADRI was established in 2004 by the public utility commissions of Delaware, the District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection.

more than five zones implemented DR programs or if greater amounts of DR participation were achieved.

This study also provides a rough estimate of benefits to DR program participants. Program participants enjoy two sources of benefits:

- The first is an energy benefit from curtailing load of much lesser value than the price of energy on the spot market. These benefits were estimated to be $85 to $234 per megawatt-hour or $9 to $26 million per year based on the results of the Dayzer simulations and some simplifying assumptions on the economic value customers placed on their curtailable load. Without making those assumptions, the range of benefits widens to $1 to $36 million.
- The second major source of benefit to program participants is the reduction in capacity needed to meet reserve adequacy requirements for a load shape that has been modified by reducing the peaks. A very rough estimate of this long-term capacity benefit is $73 million per year for curtailment of 3% of load in the five zones. More rigorous analyses of these participant benefits would be needed, along with an assessment of the costs of equipment and administration of demand response programs, in order to fully evaluate the net benefits to participants.

It is important to note that this study has not quantified several additional categories of benefits of DR. These include enhanced competitiveness of energy and capacity markets, reduced price volatility, the provision of insurance against extreme events that have not been captured in the scenarios considered, the option to curtail some load in the volatile real-time market, reduced capacity market prices, and deferred T&D costs. In addition, because this study focuses on curtailments to day-ahead schedules, it does not capture the additional benefits that real-time demand response can provide by mitigating the effects of unexpected events such as increases in load, generation outages, and transmission outages.

It is equally important to note that this study does not consider several secondary effects that could offset the benefits to non-curtailed loads. Consumers may shift load to other hours, which could somewhat increase prices in those hours. Our estimates of price effects would also be offset partially by a more muted response of customers on real-time pricing, as a consequence of the lower market prices. Moreover, reduced energy prices and reductions in the demand for capacity could accelerate the retirement of old capacity and/or delay the construction of new capacity, leading to an eventual increase in energy prices relative to our estimated price reductions. In addition, assuming that energy and capacity markets reach competitive equilibrium, a reduction in energy market prices and hence energy margins would likely trigger an increase in capacity prices as suppliers raise capacity bids to recover their going-forward fixed costs. We have not analyzed where and when such competitive equilibrium conditions can be expected, how long it will take for the energy market impact to be offset by capacity effects, or how complete the offset is likely to be.

Ultimately, the long-term benefits will be determined by the extent to which adding DR to the resource mix lowers total resource costs. Although the energy and capacity-related effects quantified in this study are related to resource costs, a comprehensive analysis of total resource costs, including an assessment of the likely technology mix of future capacity and DR, is a question that has not been addressed in this study.

Our conclusions are summarized in Table 1.

Table 1. Annual Benefits from 3% Load Reduction in the top 100 Hours in 5 MADRI Zones

	Quantified Benefits in MADRI States	Quantified Benefits in Other PJM States	Unquantified Benefits	Caveats
Benefits to Non-Curtailed Load	**$57-182 Million** (energy only) **(5-8%** price reduction in curtailed hours)	**$7-20 Million** (energy only) **(1-2%** price reduction in curtailed hours)	• Capacity price decrease due to reduced demand; • Enhanced competitiveness in energy and capacity markets; • Real-time vs. day-ahead; • Value of reduced volatility; • Insurance against extreme events; • Avoided T&D costs.	• Probably significantly offset in long-run equilibrium as capacity and capacity prices adjust; "long-run" might not be so long. • Load shifting and demand elasticity offest some benefit in short-term.
Energy Benefits to Curtailed Load	**$9-26 Million** **($85-234/MWh** price reduction in curtailed hours)	n/a	n/a	• Based on simplifying assumptions regarding the value of load that is curtailed.
Capacity Benefits to Curtailed Load	**$73 Million** (assuming **$58/kW-Yr)**	n/a	n/a	• Based on generic long-run cost of avoided capacity; • Ignores costs of equipment and DR program administration.
Total Annual Benefits	**$138-281 Million**	**$7-20 Million**	• Additional benefits to non-curtailed load could be large.	• Includes both the solid economic efficiency gains to curtailed load and the less robust benefits to non-curtailed loads.

2.0 STUDY SCOPE AND ORGANIZATION OF THIS REPORT

This study focuses primarily on estimating the direct impact of reductions in peak loads on energy market prices. Under tight market conditions, a small reduction in demand can result in a large reduction in spot prices because the supply curve in the high demand range is steeply sloping upwards. Changes in spot prices not only affect spot transactions, but also influence the pricing of longer-term transactions to the extent that market participants anticipate such changes in spot prices. With lower market prices, demand reductions will tend to lower payments to generators and reduce overall energy costs to load, relative to the less efficient situation in which demand is unable to respond to market signals. This study estimates the magnitude of price reductions and resulting benefits to non-curtailed loads caused by demand curtailments during peak periods, as described in Section 3.

The study also includes an estimate of the benefits to curtailed loads, since these important benefits could be informed by the simulations already performed. Curtailed loads receive both an energy benefit and a capacity benefit. The energy benefit derives from eliminating marginal uses of energy that are of lesser value than the marginal cost of generation. The capacity benefit derives from the fact that curtailment of peak loads “flattens” the load shape, thus reducing the total amount of capacity needed to meet peak load. The methodology for estimating benefits to curtailed loads is described in Section 4.

Given the tight time frame within which this study was performed, we did not analyze several categories of additional benefits and offsetting factors. These benefits and offsets are discussed qualitatively in Section 5 of this report and may be analyzed in greater depth as part of a “Phase II” study by MADRI or PJM.

Section 6 discusses the conclusions from this study.

3.0 ENERGY MARKET IMPACTS AND RESULTING BENEFITS TO NON-CURTAILED LOADS

3.1. Overview of Methodology

In order to estimate short-term price impacts of demand curtailment, PJM, working with the MADRI states, issued a request for proposal (RFP) for a study simulating the PJM market with and without demand curtailments in peak hours. The RFP outlined the study methodology that was developed through the MADRI stakeholder process. The study was to estimate the LMP reductions from curtailing demand in the BG&E, Delmarva, PECO, PSEG, and PEPCO control zones, by three percent (3%) in the top twenty (20) five-hour (5-hr) priced blocks[3] that occurred during 2005 under various load conditions and fuel prices: an actual peak load case (AP), a weather-normalized case (N), a high peak load case (HP), a low peak load case (LP), a high fuel case (HF), and a low fuel case (LF). For each case, the direct impact of demand curtailment on load's locational marginal prices (LMPs) and financial transmission rights (FTRs) revenues was to be calculated.

The Brattle Group's analysis was conducted using the state-of-the art locational power market simulation model, "Dayzer." Dayzer is well-suited to this study because of its capabilities to simulate actual markets accurately. In addition to capturing the basic elements of supply (i.e., every generating unit and its characteristics), demand (every load bus in every load zone), and transmission (i.e., the actual load flow used by PJM), Dayzer also captures the daily and hourly fluctuations in market conditions that can cause changes in prices and transmission congestion. The data structures in Dayzer are synchronized daily with publicly available datasets from PJM and other sources by CES, including data regarding actual unit outages, hourly dynamic ratings of transmission lines, actual daily transmission outages, actual hourly interchanges with neighboring RTOs, and actual daily variations in spot prices for fuels. As a result, Dayzer can accurately replicate actual LMPs, including the LMPs during the super-peak hours when curtailments would occur.

We estimated the impact of demand curtailment on day-ahead power prices in the PJM market. The analysis was performed in the following four steps:

1. Develop an accurate representation of the PJM market in 2005 by refining the Dayzer model's input data, and by calibrating and validating the model outputs against actual market data.
2. Construct and simulate reference cases against which the impact of demand curtailments will be assessed.

[3] These particular specifications were developed through the MADRI stakeholder process to represent a range of DR programs that could reduce load during critical-peak periods. DR programs can include real-time pricing programs, critical-peak pricing programs, and various forms of curtailment programs, including direct load control of residential air conditioners, curtailable and interruptible rate programs for commercial and industrial customers, and cash-incentive based programs for customers who curtail load when called upon for economic reasons.

3. Construct and simulate curtailment cases in which each selected zone's load is curtailed by 3% in the top twenty (20) five-hour (5-hr) blocks from the corresponding reference case.
4. Quantify price impacts and benefits to non-curtailed load (net of changes in FTR revenues) in each curtailment case relative to each corresponding reference case.

It is important to note that this methodology estimates the market impact of day-ahead (DA) curtailments, not real-time curtailments, because Dayzer (and other similar models) simulates the day-ahead market more realistically than the real-time market. Such models are almost never used to simulate real-time markets because they lack the last minute surprises that cause real-time uncertainty and price volatility. Rather, these models commit and dispatch according to a load forecast and a known set of available resources that do not vary between commitment (day-ahead) and actual dispatch (real time). Such certainty does not produce the volatility that characterizes the real-time market. Therefore, this study does not capture the additional value of an option to curtail demand on a real-time basis. In real time, prices can spike due to unexpectedly high load and forced generation and transmission outages, which can create scarcity and may force the RTO to rely on high-cost blocks of emergency energy that have been bid into the market.

3.2. Refinement of Input Data; Calibration and Validation of the Model

3.2.1. Refinements to Input Data

The Dayzer model takes as inputs all of the elements of supply, demand, and transmission in the PJM Interconnection, with more limited data regarding neighboring systems. All data necessary for simulating historical periods are provided by CES, but in order to represent the 2005 PJM market as accurately as possible, we worked closely with PJM staff to update and refine nearly all categories of input data, as summarized in Table 2 below. Given these refinements, the model is replicating the fundamentals of supply, demand, and transmission as closely as reasonably possible based on data that is publicly available (except for unit outages, which are confidential).

Table 2: Data Sources and Refinements

Category of Inputs		Sources and Refinements
Supply	Capacity Online	Compared data in Dayzer to confidential unit data provided by PJM and made changes where necessary to achieve consistent aggregate capacity in each zone, by technology.
Supply	Generator Characteristics	Heat rates and emissions rates from *Energy Velocity*, based on CEMS and FERC filings. For each technology type, used generic assumptions for heat rate shapes, variable O&M costs, minimum-up-time, startup costs, and other characteristics.
Supply	Fuel Prices	*Gas* : ICE Daily spot prices for each Transco Zone + local distribution charges *Oil* : NYMEX spot prices for FO2, FO6 + historical transportation differentials *Coal* : Based on EIA-423's and NYMEX spot prices (data for all fuels provided by CES).
Supply	Emission Allowance Prices	Daily spot prices from Cantor Fitzgerald (data provided by CES).
Supply	Generator Outages	Confidential unit outage schedules from PJM.
Supply	Imports/Exports from Outside PJM	Actual day-ahead scheduled hourly interchanges at each interface point (data provided by CES).
Supply	Unit Bids	Calibrated unit bids to publicly available bid data, by region and by technology type
Demand	2005 Hourly Load by Zone	Implemented actual 2005 real-time load in each zone; used real-time load as proxy for load expectations underlying the day-ahead market (data provided by CES).
Demand	Operating Reserve Requirements	Actual hourly PJM requirements (data provided by CES).
Transmission	Load Flow Case (represents transmission system and load distribution in each zone)	PJM's load flow case used for its 2005 FTR auction.
Transmission	Flow Limits	Actual hourly limits on reactive interfaces. For thermal limits, conformed to actual flow limits posted at http://oasis.pjm.com/doc/PJM_Line_Ratings.txt.
Transmission	Transmission Outages	Actual line outages downloaded from PJM (provided by CES).

Source and Notes:
* "CES" refers to Cambridge Energy Solutions, the provider of the Dayzer software, CES propriety data, and daily downloads of data from the PJM website.
** *Energy Velocity* is part of Global Energy Decisions Inc's *Velocity Suite*.

3.2.2. Calibration of Bids

Because the theoretical marginal cost bids developed for use in Dayzer are based on estimated parameters, we calibrated the Dayzer marginal cost bids to capture additional factors incorporated into actual bids. Marginal costs for each unit in Dayzer are given by the following equation:

Marginal costs = Estimated incremental heat rates × Index-based spot fuel prices +
Estimated emissions rates × Allowance prices +
Generic assumptions for variable operating and maintenance costs (VOM).

Some cost components are only approximated and may not be sufficiently accurate under certain conditions. For example, heat rates and corresponding emissions do not vary based on ambient temperature and plant conditions; generic VOM assumptions do not consider how bidders may allocate periodic maintenance costs over their expected operating hours; and zonal fuel prices may be insufficiently granular. Actual unit cost-based bids can also include opportunity costs related to environmental constraints or special operating constraints and must conform to the Market Monitoring Unit's Cost Determination Task Force Standards.[4]

The Dayzer bids were calibrated using the publicly available PJM Daily Energy Bids Data.[5,6] This dataset provides unit-level price bids that PJM publishes with a 6-month lag. Although the publicly available data does not identify individual units by name, we were able to determine each unit's approximate location within PJM based on the date when each unit first appears in the dataset. Units in PJM-East have been present in the dataset since June 2000 (except for new units); those in APS, ComEd, AEP, Dayton, Duquesne, and Dominion have appeared on or around the dates that the respective regions joined PJM.

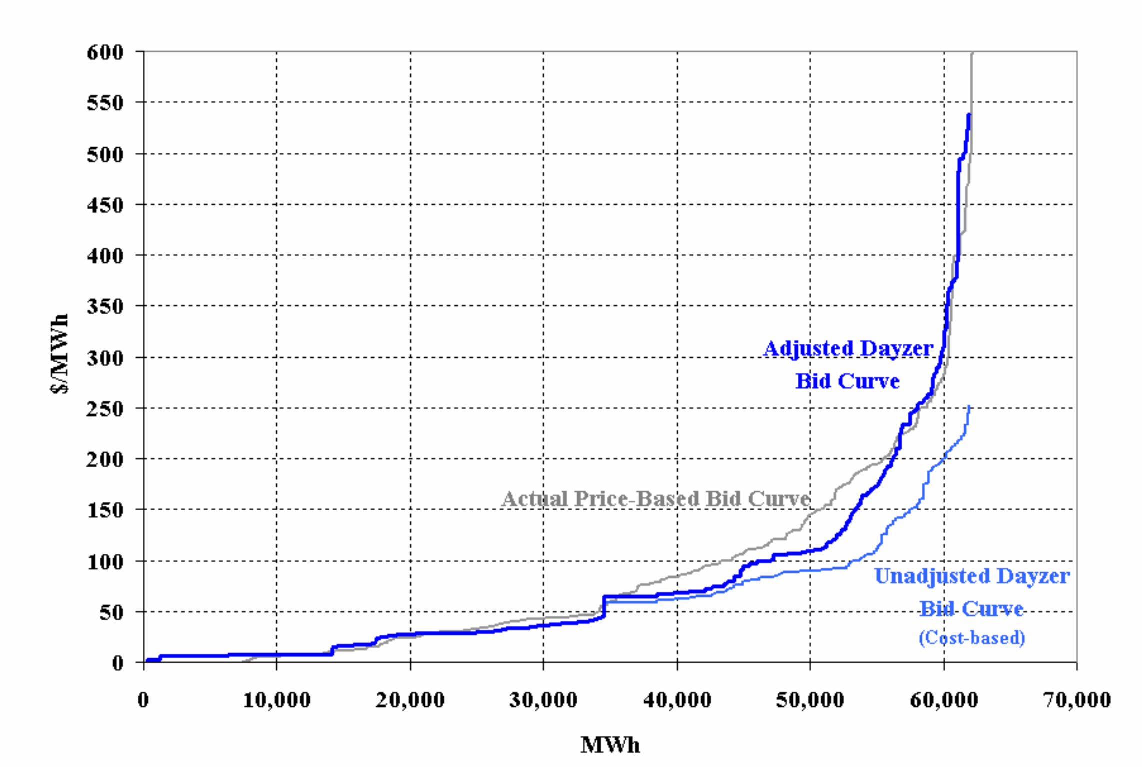
Figure 1 compares the initial cost-based bid curve for PJM-East to the adjusted bid curve and the actual price-based bid curve for one day, July 12, 2005. Similar adjustments were made for the other regions.

[4] *PJM Manual 15: Cost Development Guidelines* recognizes opportunity costs as costs incurred when "the provision of a product prevents the provision of another product with a higher value." For example, if a unit has only a limited number of annual run hours, and if the unit is dispatched as must run by PJM to relieve a transmission constraint, the opportunity cost of providing must-run output is the value associated with the foregone opportunity to supply energy during a higher valued time period. (See http://www.pjm.com/contributions/pjm-manuals/pdf/m15.pdf). These guidelines do not apply to price offers or to certain generation units installed between July 9, 1996 and September 30, 2003, which are exempt from cost-based offer caps. (See Section 6.5 of *Amended and Restated Operating Agreement of PJM Interconnection, L.L.C.* at http://www.pjm.com/documents/downloads/agreements/oa.pdf.)

[5] Available at http://www.pjm.com/markets/jsp/bids-emarket.jsp.

[6] Note that constructing a PJM supply curve from these data assumes the absence of system or operational constraints and the absence of unit specific bid parameters, both of which would limit the in-merit availability of the offer blocks. The data set also does not indicate whether the bids represent cost or price based offers, or whether the offer listed was the offer upon which the units were or would have been committed in actual dispatch.

Figure 1. PJM-East Actual Bid Curve vs. Dayzer Bid Curves (July 12, 2005)



3.2.3. Model Calibration and Validation

The final Dayzer backcast of actual 2005 market conditions appears to be quite accurate, particularly during peak hours. As Table 3 shows, simulated PJM Eastern Hub prices are within $6 per megawatt-hour (3%) of actual day-ahead average prices during the top 100 hours and within $6 per megawatt-hour (6%) of the average price over all peak hours.

The accuracy of the Dayzer simulation is lower in shoulder and off-peak hours, possibly because of the remaining gap between adjusted Dayzer bids and actual bids in the $50-$200/MWh range of the PJM-East bid curve. Accuracy is also more limited in the Western zones of ComEd, AEP, Dayton, and Duquesne, where simulated prices are overstated in the top 300 hours. In addition, simulated prices are low in the Dominion service area, possibly because of high bids and under generation in the West, hence lower congestion on the West-East constraints that tend to have a disproportionate effect on prices in PEPCO and Dominion. Finally, a price spike is missing in PECO because Dayzer is not capturing the extreme congestion that occurred in August, 2005 on the Whitpain transformer between the 500 kV system and the PECO service territory.

Table 3. Differences Between Average Simulated Prices and Average Actual DA Prices

Region	Zone Name	Actual		Dayzer		Dayzer Minus Actual	
		Top 100 Hours	Jun-Sep Avg Peak	Top 100 Hours	Jun-Sep Avg Peak	Top 100 Hours	Jun-Sep Avg Peak
South	DOM	$181	$100	$151	$91	($31)	($9)
East	PEPCO	$212	$110	$207	$99	($6)	($11)
East	BGE	$200	$106	$191	$99	($8)	($7)
East	DPL	$193	$104	$200	$99	$7	($5)
East	AECO	$205	$111	$203	$106	($1)	($5)
East	PECO	$203	$106	$186	$96	($17)	($10)
East	METED	$192	$103	$199	$96	$7	($7)
East	PSEG	$189	$104	$187	$99	($2)	($5)
East	JCPL	$184	$101	$181	$94	($3)	($7)
East	RECO	$179	$100	$167	$87	($13)	($13)
East	PPL	$187	$101	$179	$92	($8)	($8)
East	PENELEC	$144	$83	$170	$80	$25	($3)
East	EASTERNHUB	$198	$105	$203	$99	$6	($6)
East	WESTERNHUB	$164	$91	$168	$84	$3	($8)
Mid	APS	$164	$88	$186	$78	$22	($10)
Mid	DUQ	$118	$65	$142	$59	$24	($6)
West	AEP	$128	$72	$136	$63	$8	($8)
West	DAY	$123	$69	$136	$62	$13	($7)
West	AEPDAYTONHUB	$126	$70	$137	$63	$11	($8)
West	AEPGENHUB	$121	$68	$133	$60	$11	($8)
West	COMED	$127	$71	$137	$63	$10	($8)
West	NILLINOISHUB	$126	$71	$137	$63	$11	($8)

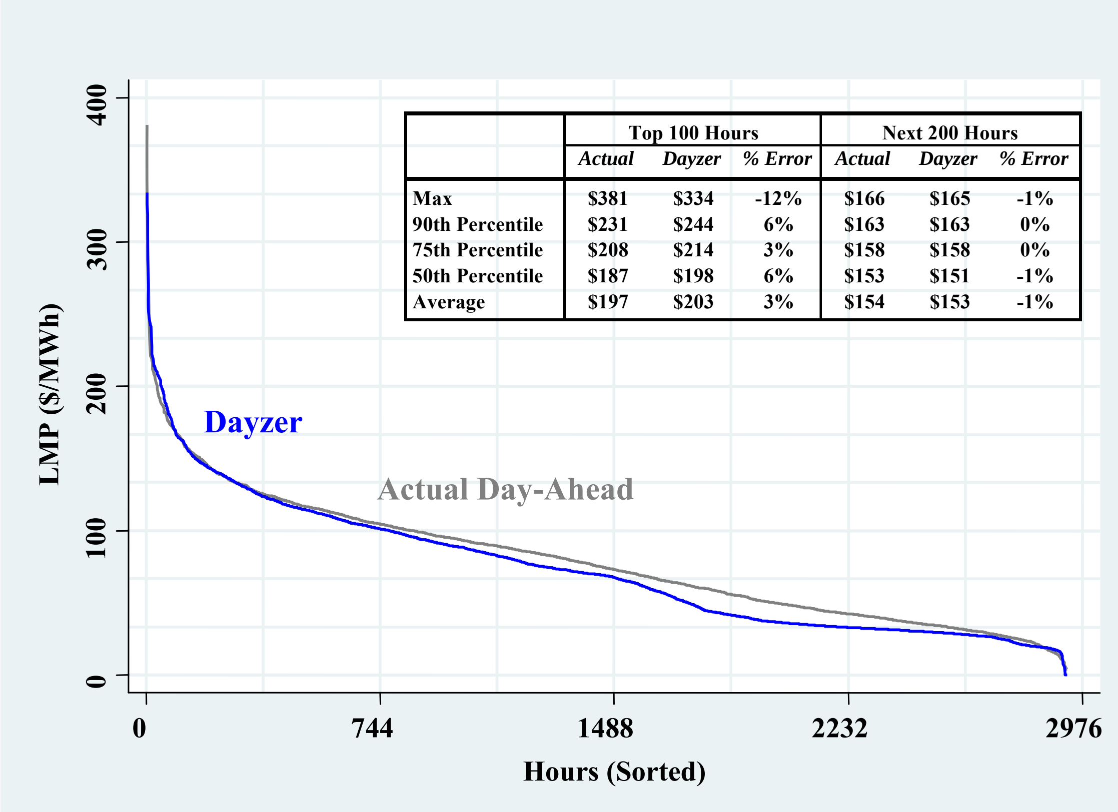
Source and Notes:
Actual LMPs from Global Energy Decision Inc.'s *Velocity Suite*, August 2006 data release.
"Peak" defined as hour ending 7 through 22 Monday through Friday, except for NERC holidays.

Importantly, however, the Dayzer prices are the most accurate during the top few hundred hours, including the super-peak periods on which this study focuses. The price duration curves in Figure 2 show close replication of actual day-ahead prices during the top hours.

It is theoretically possible to calibrate Dayzer more precisely, but the precision would still be limited by the quality and the lack of specificity in the public bid data. Furthermore, even if the actual daily bids for every unit were available, replicating actual day-ahead prices exactly would be nearly impossible for a variety of reasons, including:

- Actual unit startup costs and operating constraints could be more constraining than the standard assumptions in Dayzer.
- The real-time load used in the model is only a proxy for expected day-ahead loads; there will always be differences due to market participants' imperfect forecasts.
- Imports from outside PJM can set market prices in PJM, but Dayzer represents them as non-price-setting fixed injections in order to replicate actual day-ahead scheduled flows.
- The model is not capturing some dynamic transmission limits and operating procedures for which public data was not available.
- Dayzer assumes a time-invariant distribution of load among buses in each load zone.

Figure 2. Comparison of Eastern Hub LMP Duration Curves (June-September, 2005)



	Top 100 Hours			Next 200 Hours		
	Actual	*Dayzer*	*% Error*	*Actual*	*Dayzer*	*% Error*
Max	$381	$334	-12%	$166	$165	-1%
90th Percentile	$231	$244	6%	$163	$163	0%
75th Percentile	$208	$214	3%	$158	$158	0%
50th Percentile	$187	$198	6%	$153	$151	-1%
Average	$197	$203	3%	$154	$153	-1%

3.3. Development of Reference Cases

Based on the 2005 "backcast" simulations described above, *The Brattle Group* constructed and simulated reference cases against which the impact of demand curtailments were to be assessed. In order to capture a range of possible market conditions, we adopted the 2005 backcast as the "actual peak" (AP) reference case and created several alternative reference cases with loads and fuel prices that differ from the actual peak.

3.3.1. The Normalized (N) Case

The most atypical attributes of the 2005 market were the hurricane-induced fuel price disruptions and the load shape. *Brattle* constructed a Normalized Case by adjusting both of these variables.

Load was normalized by starting with a load profile for each zone in the year 2002, which was a year that PJM staff deemed to be "typical". Then each zone's hourly load was multiplied by the demand growth implicit in the differences between the 2002 weather-normalized peak load and the 2005 weather-normalized peak load. This methodology produced a peak load that was approximately 4% higher than the 2005 weather-normalized peak reported by PJM,[7] consistent

[7] 2006 PJM Load Forecast Report, Table B1, p. 29.
Available at http://www.pjm.com/planning/res-adequacy/downloads/2006-pjm-load-report.pdf.

with the fact that cooling-degree days and peak loads in the 2002 base-year were above normal.[8] Hence, the "Normalized" Case is actually above normal for 2005 and might be considered more nearly representative of a normal 2007-08, when load is projected to be 3.2-4.9% higher[9] without major capacity additions.[10]

To approximate "normal" natural gas and distillate oil (FO2) prices, one-year NYMEX futures traded in 2006 for delivery in the same month of 2007 were used. For example, the Henry Hub gas price used for July 26, 2005 in the normalized case is given by the price of futures traded on July 26, 2006 for delivery in July 2007. The resulting normalized prices during the June through September period were on average at $8.3/MMBtu for Henry Hub and at $14.9/MMBtu for FO2, somewhat higher than currently-traded futures for delivery in July, 2007 of $7.6/MMBtu for gas and $11.9/MMBtu for FO2.[11]

No residual oil (FO6) futures are traded on NYMEX, so normalized FO6 prices were derived from futures prices for crude oil. First, a relationship between FO6 and crude spot prices was identified through a regression model, and then the regression coefficients were used to project normalized FO6 prices based on futures prices for crude oil. The resulting average FO6 price was $7.0/MMBtu for June through September.

To normalize emission allowance prices, an average of actual daily spot prices was applied across the entire June through September 2005 study period. The resulting prices were $2,435/ton and $831/ton for nitrogen oxide (NOx) and sulfur oxide (SOx) respectively.

3.3.2. The High Peak (HP) and Low Peak (LP) Cases

The High Peak (HP) and Low Peak (LP) cases were constructed from the Normalized (N) case, but with load inflated or deflated to reflect one-in-twenty-year conditions. Twenty-year conditions were determined by comparing actual peaks to weather-normalized peaks for each year from 1984 to 2004.[12] Actual peaks differed from normalized peaks by -8% to +5%, which was approximated as +/- 6%.[13] This factor was applied to scale up/down the hourly loads from the Normalized case to arrive at the High/Low Peak cases.

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[8] Available at http://www.ncdc.noaa.gov/oa/documentlibrary/hcs/hcs.html#52overview.

[9] PJM projects a 1.6% annual growth rate in peak load, amounting to a 3.2% and 4.9% increase over the normalized 2005 load in 2007 and 2008, respectively. See the 2006 PJM Load Forecast Report, page 1.

[10] According to the 2005 PJM State of the Market Report, p.133, total installed capacity in PJM as of Dec 31, 2005 was 163,471 MW. This is projected to increase by 0.6% and 1.5% in 2007 and 2008 respectively. Available at http://www.pjm.com/planning/res-adequacy/downloads/20061228-forecasted-reserve-margin-correction.pdf.

[11] Current prices from NYMEX on January 29, 2007 are available at http://www.nymex.com; FO2 is assumed to have a heat content of 139,000 Btu per gallon.

[12] 2005 PJM Load Forecast Report. Available at http://www.pjm.com/planning/res-adequacy/downloads/2005-load-forecast-report.pdf.

[13] As a point of reference, the PJM load during the extreme heat spell in July/August of 2006 exceeded the weather-normalized peak by 6.2%. 2006 hourly load data are available at http://www.pjm.com/services/system-performance/downloads/historical/2006-hourly_loads.xls. Weather normalized peaks are available at http://www.pjm.com/planning/res-adequacy/downloads/summer-2006%20-peaks-and-5cps.pdf.

3.3.3. The High Fuel (HF) and Low Fuel (LF) Cases

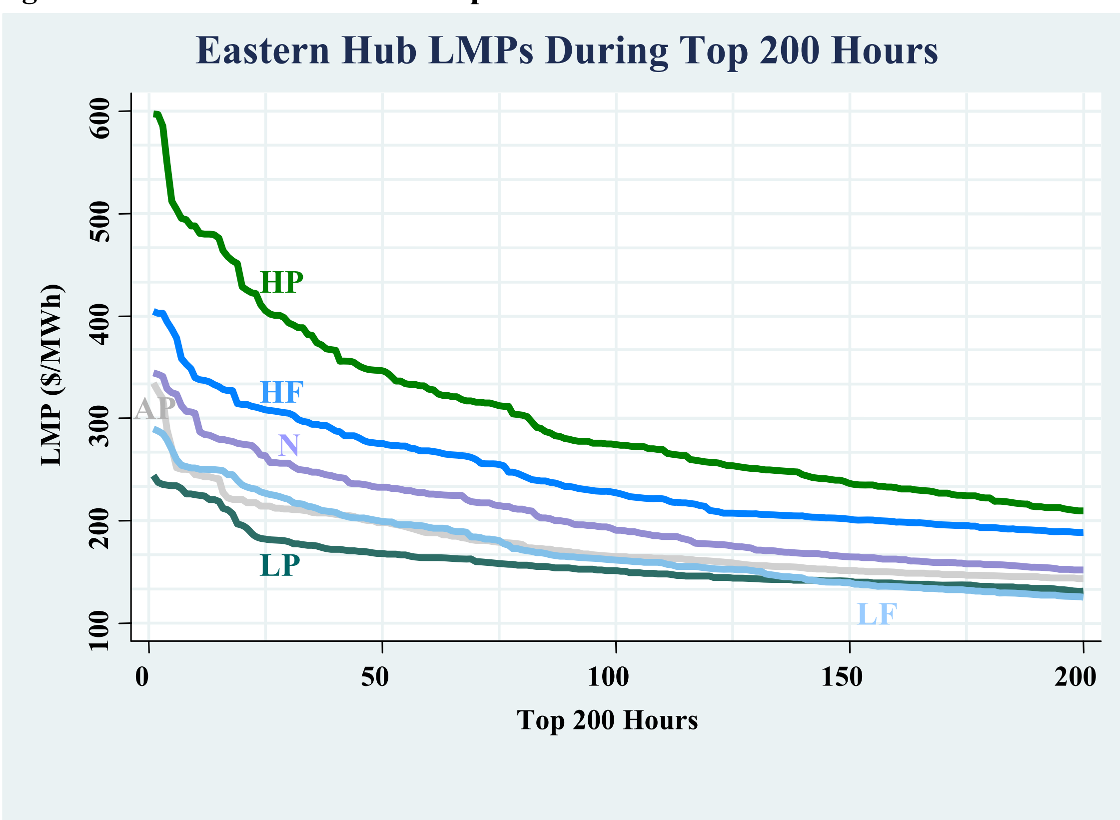
The HF and LF cases represent an 80% confidence interval around the 2007 forward prices for gas and oil, based on historical distributions describing the ratios of spot prices to 1-year forwards transacted one year prior. The 90th and 10th percentiles of these ratios were then applied to the normalized prices to yield the high and low prices, respectively. As a result, the average prices in the HF and LF cases are: $10.1/MMBtu and $6.4/MMBtu for Henry Hub, $8.4/MMBtu and $6.3/MMBtu for residual oil, and $17.9/MMBtu and $13.3/MMBtu for distillate oil.

NOx and SOx allowance costs were also varied because they tend to be related to fuel prices. In the HF case, NOx allowance prices were set at $3,020/ton and SOx allowance prices at $1,330/ton, corresponding to the highest daily prices observed in June through September of 2005. In the LF case, NOx allowance prices were set at $2,050/ton and SOx allowance prices at $745/ton, corresponding to the lowest daily prices observed in June through September 2005.

3.3.4. Simulation of Reference Cases

Each of the reference cases was simulated separately using Dayzer. Figure 3, below, shows that these cases span a large range of market conditions and prices.

Figure 3. Eastern Hub Prices in Top 200 Hours in Six Reference Cases



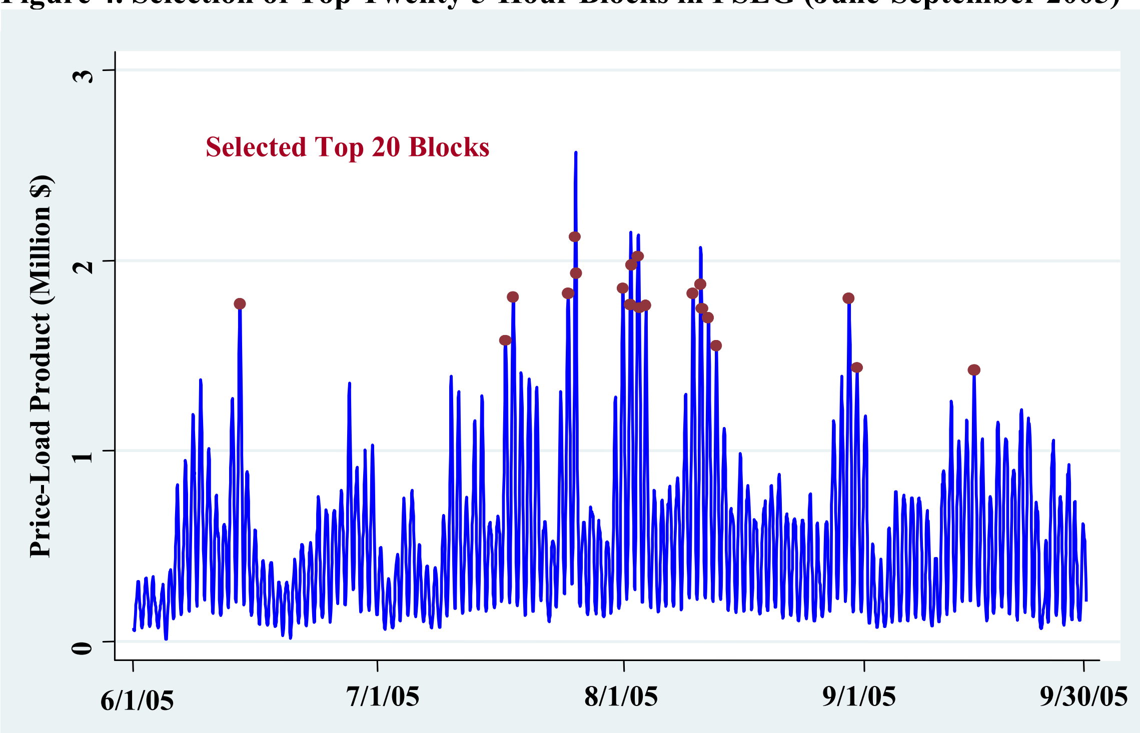
Notes: AP= Actual Peak; N = Normalized; HP = High Peak; LP = Low Peak; HF = High Fuel; LF = Low Fuel.

3.4. Development of Curtailment Cases

3.4.1. Identification of Top Twenty 5-Hour Blocks

One curtailment case was developed for each reference case, with all data inputs the same as the corresponding reference case, except for the hourly load, which was reduced by 3% in the top twenty 5-hour blocks in the five curtailment zones. The top blocks were selected based on the price-load product rather than price alone because reducing prices in an hour with high load benefits customers more than reducing prices by the same amount in an hour with low load.[14] The selection of top blocks was performed individually for each of the five zones. The red dots in Figure 4 below indicate the identified hours for the PSEG zone in the Actual Peak case; top blocks were selected similarly for the other four target zones and for all of the other cases.[15]

Figure 4. Selection of Top Twenty 5-Hour Blocks in PSEG (June-September 2005)



Notes:
The plot shows 5-hour moving averages of the hourly price-load products.
"Hourly price-load product" defined as Dayzer simulated LMP multiplied by real-time load in the corresponding hour.

[14] DR programs could be designed to target the highest priced hours rather than the highest price-load hours, but the results would be similar because of the high correlation between hourly prices and load.
[15] In actual 2005 market conditions, all of the top price-load blocks occurred in the summer, which enabled us to limit the simulation period to June through September.

3.4.2. Simulation of Curtailment Cases

Each curtailment case was constructed from the corresponding reference case, with hourly zonal loads reduced by 3% during the top blocks identified for each zone. It is important to note that the top blocks in one zone do not always coincide with those in another, so there are hours in which the load is reduced in only one zone. Moreover, even when 3% of load is curtailed in all five zones simultaneously, the combined curtailment in the five zones does not exceed 1,200 MW, which is only 0.9% of the peak load across all zones in PJM.

For the curtailment cases, we used the same unit commitment schedule as in the corresponding reference cases, but allowed combustion turbines to ramp down to zero. Holding unit commitment fixed was necessary in order to prevent the price "noise" normally produced by unit commitment from overwhelming the price reductions caused by curtailment. Unit commitment can be noisy because of the discrete choice nature of the problem (a unit is either on or off) and because of limitations in any commitment algorithm's ability to find the absolute optimum solution to the problem. With load curtailments of 100-1,200 MW (about the size of just a few units), the algorithm can produce a different unit commitment solution that changes prices substantially and misleadingly. Holding the unit commitment schedule constant avoids such noise.

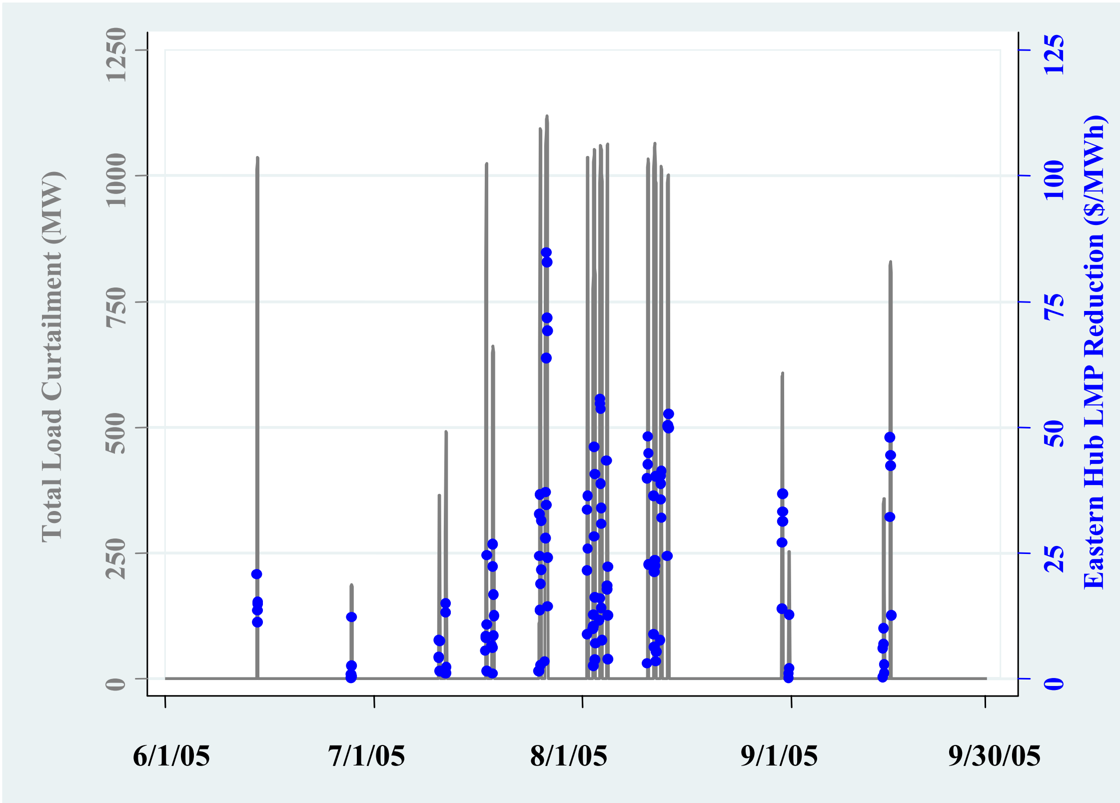
3.5. Estimation of Benefits to Non-Curtailed Loads

3.5.1. Direct Energy Price Impact

Comparing prices in the curtailment cases to those in the corresponding reference cases isolates the direct impact of load curtailment on prices. Figure 5 shows the hourly price impact on PJM Eastern Hub for the AP case. The blue dots, to be read against the right-hand y-axis, represent hourly price changes, while the grey lines, to be read against the left-hand y-axis, show the hourly quantities of curtailment driving the price reductions.[16] Similar illustrations of price impacts for the other cases are presented in Figures A2-A6 of the Appendix.

[16] These figures do not consider the additional benefits or offsetting effects that are discussed in Section 5.2.

Figure 5. Impact of Load Curtailment on Prices at PJM Eastern Hub (AP Case)



These results are also tabulated in columns A-D of Table 4, which shows that curtailing less than 2% of load in MADRI states reduces prices by $8-$25 per megawatt-hour (5-8%) during the 133-152 hours in which at least one zone's load is curtailed. The percentage decrease is relatively uniform across states, except in Delaware, where prices decrease by 6-12% because curtailment relieves very high shadow prices on the North Seaford transformer. Actual congestion in 2005 was not quite as high as it appears in Dayzer, so the simulated price impact in Delaware is likely somewhat overstated.

Table 4. Price Impacts and Benefits to Non-Curtailed Loads by State

	Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Direct Benefits	ARR Change	Net Direct Benefits
	($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
Actual Peak (AP) Case (during 137 hours in which load is curtailed in at least one zone)								
PA	**$11**	**5.8%**	**172**	**0.7%**	**25,514**	**$36.7**	**($6.3)**	**$30.4**
NJ	**$13**	**6.7%**	**211**	**1.2%**	**17,282**	**$29.7**	**($1.6)**	**$28.1**
DE	**$21**	**10.6%**	**57**	**2.2%**	**2,482**	**$7.3**	**($1.6)**	**$5.7**
MD	**$12**	**6.0%**	**259**	**2.0%**	**12,886**	**$20.8**	**($4.3)**	**$16.5**
DC	**$13**	**6.0%**	**41**	**2.2%**	**1,791**	**$3.1**	**($0.9)**	**$2.2**
MADRI Total	**$12**	**6.7%**	**740**	**1.2%**	**59,955**	**$97.5**	**($14.7)**	**$82.9**
Normalized (N) Case (147 hours)								
PA	**$11**	**5.2%**	**167**	**0.6%**	**26,435**	**$42.4**	**($8.8)**	**$33.6**
NJ	**$14**	**6.4%**	**208**	**1.1%**	**17,954**	**$35.9**	**($1.6)**	**$34.3**
DE	**$27**	**11.9%**	**53**	**2.1%**	**2,537**	**$10.0**	**($2.7)**	**$7.2**
MD	**$15**	**6.4%**	**252**	**1.8%**	**13,501**	**$29.3**	**($6.1)**	**$23.2**
DC	**$17**	**7.1%**	**40**	**2.1%**	**1,877**	**$4.8**	**($1.3)**	**$3.5**
MADRI Total	**$13**	**7.1%**	**721**	**1.1%**	**62,304**	**$122.4**	**($20.5)**	**$101.9**
High Peak (HP) Case (133 hours)								
PA	**$23**	**6.7%**	**195**	**0.7%**	**28,158**	**$84.5**	**($21.9)**	**$62.6**
NJ	**$26**	**8.0%**	**244**	**1.3%**	**19,152**	**$66.8**	**($2.4)**	**$64.5**
DE	**$37**	**10.4%**	**62**	**2.3%**	**2,668**	**$13.1**	**($1.2)**	**$11.9**
MD	**$24**	**7.4%**	**295**	**2.0%**	**14,277**	**$45.3**	**($7.2)**	**$38.1**
DC	**$25**	**7.8%**	**46**	**2.3%**	**1,984**	**$6.7**	**($1.4)**	**$5.3**
MADRI Total	**$25**	**7.9%**	**842**	**1.3%**	**66,238**	**$216.5**	**($34.0)**	**$182.4**
Low Peak (LP) Case (151 hours)								
PA	**$7**	**4.3%**	**152**	**0.6%**	**24,936**	**$27.2**	**($7.9)**	**$19.3**
NJ	**$9**	**5.3%**	**191**	**1.1%**	**16,874**	**$22.8**	**($1.6)**	**$21.2**
DE	**$10**	**5.8%**	**48**	**2.0%**	**2,375**	**$3.5**	**($0.2)**	**$3.3**
MD	**$8**	**4.8%**	**230**	**1.8%**	**12,703**	**$15.8**	**($4.0)**	**$11.9**
DC	**$9**	**5.0%**	**36**	**2.0%**	**1,770**	**$2.4**	**($0.7)**	**$1.6**
MADRI Total	**$8**	**5.0%**	**657**	**1.1%**	**58,657**	**$71.7**	**($14.4)**	**$57.3**
High Fuel (HF) Case (135 hours)								
PA	**$15**	**6.0%**	**182**	**0.7%**	**26,571**	**$53.6**	**($9.0)**	**$44.6**
NJ	**$19**	**7.3%**	**227**	**1.2%**	**18,040**	**$45.7**	**($1.6)**	**$44.0**
DE	**$32**	**12.0%**	**58**	**2.2%**	**2,533**	**$11.1**	**($2.6)**	**$8.5**
MD	**$19**	**6.8%**	**274**	**2.0%**	**13,504**	**$33.9**	**($6.0)**	**$27.9**
DC	**$21**	**7.5%**	**43**	**2.2%**	**1,877**	**$5.4**	**($1.3)**	**$4.1**
MADRI Total	**$18**	**7.6%**	**785**	**1.2%**	**62,524**	**$149.6**	**($20.6)**	**$129.1**
Low Fuel (LF) Case (152 hours)								
PA	**$9**	**5.2%**	**160**	**0.6%**	**26,357**	**$36.3**	**($7.9)**	**$28.4**
NJ	**$12**	**6.8%**	**201**	**1.1%**	**17,835**	**$33.0**	**($1.9)**	**$31.1**
DE	**$23**	**12.4%**	**52**	**2.0%**	**2,520**	**$9.0**	**($2.5)**	**$6.5**
MD	**$13**	**6.6%**	**244**	**1.8%**	**13,456**	**$26.1**	**($5.5)**	**$20.6**
DC	**$15**	**7.2%**	**38**	**2.0%**	**1,874**	**$4.3**	**($1.2)**	**$3.1**
MADRI Total	**$12**	**7.3%**	**696**	**1.1%**	**62,042**	**$108.6**	**($19.0)**	**$89.6**

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

It is likely that the price effect would be larger if more than 3% of load were curtailed in the five target zones or if all load in PJM participated in curtailment programs instead of just the BG&E, Delmarva, PECO, PEPCO, and PSEG zones, which represent only 27% of PJM's total peak load.

Alternatively, of course, if fewer customers participated in load curtailment programs, the benefits would be smaller. We simulated additional normalized curtailment cases in which only one of the five zones implemented demand curtailment. Comparison of columns G and H in Table 5 shows that the resulting price impact is less than half as big as in the case in which all zones curtailed demand. This finding suggests that the energy price impact of demand curtailment in a highly-interconnected network such as PJM has the attributes of a public good.[17] The collective customer benefits are greatest if everyone participates and curtailments are coordinated across zones.

Table 5: Market Impacts if Curtailment Occurs in Only One Zone (Normalized Case)

	Only One Zone Curtailed							All Curtailed
	Weighted Average LMP Reduction		Average Curtailed Load (MW)	Average Residual Load (MW)	Gross Benefits (Million $)	ARR Change (Million $)	Net Benefits (Million $)	Net Benefits (Million $)
	($/MWh) [A]	(%) [B]	[C]	[D]	[E]	[F]	[G]	[H]
BGE	**$6**	**2.8%**	**204**	**6,597**	**$4.2**	**($0.7)**	**$3.5**	**$12.1**
Delmarva	**$23**	**10.3%**	**115**	**3,706**	**$8.6**	**($4.2)**	**$4.4**	**$10.6**
PECO	**$9**	**4.2%**	**246**	**7,939**	**$7.0**	**($1.9)**	**$5.1**	**$14.9**
PEPCO	**$14**	**5.6%**	**193**	**6,255**	**$8.5**	**($3.1)**	**$5.4**	**$11.6**
PSEG	**$8**	**3.8%**	**306**	**9,902**	**$8.2**	**($1.1)**	**$7.0**	**$19.4**

3.5.2. Gross Benefits to Non-Curtailed Loads

Gross customer savings are calculated by multiplying the Reduction in Zonal LMP by the Residual Zonal Load in each curtailed hour, assuming all load is exposed to the price reduction observed in the simulations.[18] Total gross savings over all hours are tabulated in column F of Table 4, which shows gross benefits in the MADRI states of $72-$217 million per year.

The concept can be illustrated with a supply and demand curve, shown in Figure 6. An illustrative supply curve is shown in blue; the demand curve is idealized as a vertical line with no elasticity, representing the fact that most customers are not directly exposed to changes in spot prices, so their short-term demand is unresponsive to spot prices. Load curtailment is represented as a decrease in quantity demanded, from Q_1 to Q_2. This causes the spot price to drop from P_1 to P_2. The price savings to non-curtailed load[19] is given by area **bcde**, assuming

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[17] However, in the long run, much of the energy benefit to non-curtailed loads could be offset by factors described in Section 5.2, reducing the public good attributes of demand curtailment.

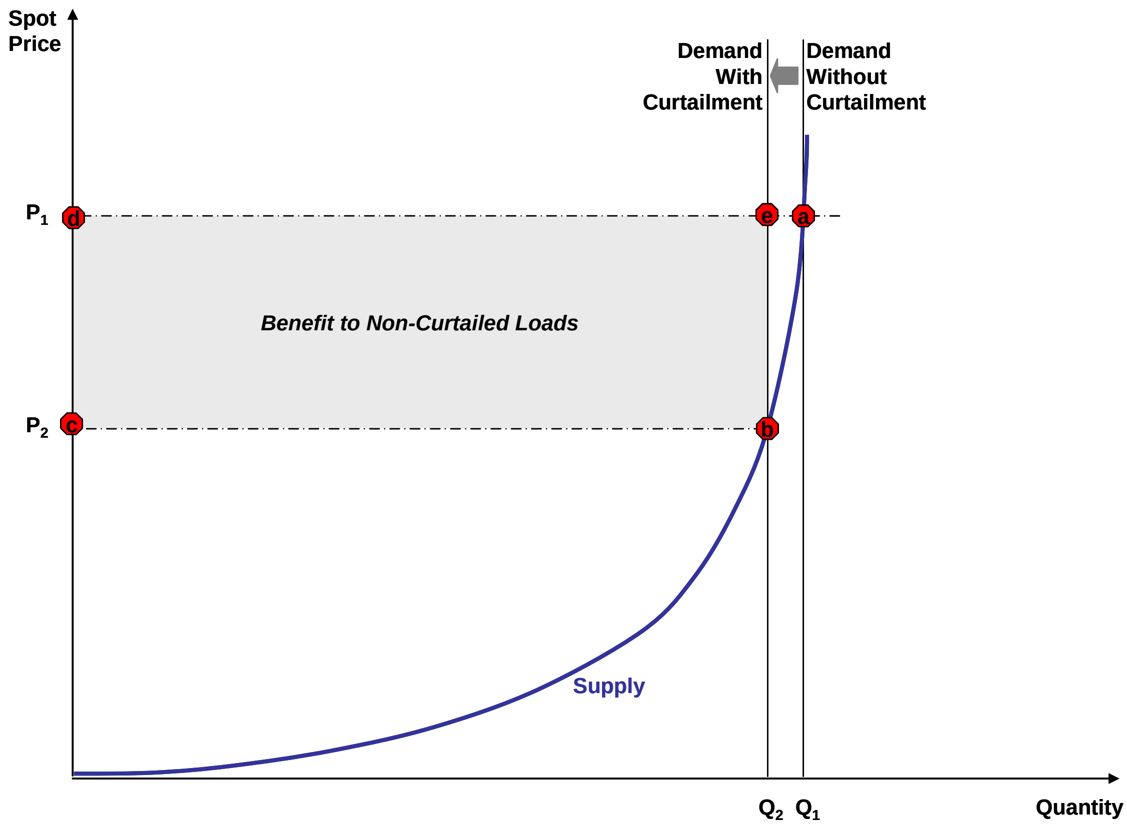
[18] The hourly change in LMP is multiplied by the hourly residual (i.e., non-curtailable) load rather than total load because load that has been curtailed does not consume energy and therefore does not benefit directly from the reduction in market prices.

[19] In this report, "load" refers generically to end-use customers and their retail providers. While benefits of unexpected changes in prices apply directly only to customers on real-time pricing and to the retail providers of other customers, the benefits of expected future price reductions apply to all end-use

none of the load is hedged though forward contracts with generators. To the extent that load is hedged through forward contracts with generators, the price savings would be reduced but only until the contracts expire.

Area **bcde** represents savings to customers, but it also represents a reduction in producer surplus relative to the less efficient situation in which demand is unresponsive to market signals. As such, this area is not a gain in economic efficiency. An efficiency gain does occur, but it accrues to the curtailed loads, as discussed in Section 4.1.

Figure 6. Conceptual Diagram of Direct Energy Benefits to Non-Curtailed Loads



3.5.3. Net Benefits to Non-Curtailed Loads

Gross benefits ignore changes in the value of FTRs. Net savings are calculated by subtracting the change in customers' FTR revenues from the gross savings. This calculation was performed using auction revenue rights (ARRs) rather than actual FTR holdings because ARRs reflect the customers' total allocated property rights to FTR revenues, whereas actual FTR holdings reflect auction outcomes and trading decisions. It was assumed that ARRs fully reflect all simulated

customers, assuming a competitive retail market and/or competitive wholesale provision of standard offer service in which rates reflect wholesale market costs.

changes in associated FTR revenues, as if bidders in the FTR auctions were able to fully anticipate the effect of demand curtailment programs on FTR revenues and bid accordingly.

The ARR revenues were calculated by multiplying the volume of each ARR by the simulated hourly LMP differential between the associated source and sink locations. PJM provided the necessary confidential data on ARR allocations.

The results of these calculations are summarized in columns G and H of Table 4, which shows that the reduction in ARR revenues reduces the total gross benefits by 14-20% overall, and as much as 5-28% in Delmarva. The intuition behind these reductions is that the gross benefits calculation assumes incorrectly that all customers pay the LMP measured at the load zone, where prices tend to be most sensitive to load curtailments. In fact, the financial effect of ARRs/FTRs is to allow loads to pay the LMPs at their generation sources, which tend to be lower and less sensitive to curtailments than the load LMP. The net measure of benefits accounts for this difference.

Netting out the reduction in ARR revenues, the benefits to non-curtailed loads in MADRI states becomes $57-$182 million per year, as shown in column H of Table 4. Outside of the MADRI states, spillover price effects produce an additional $7-$20 million in net benefits, for a total of $65-$203 million in net benefits to non-curtailed loads throughout PJM, resulting from less than 1% demand reduction in just 100 hours in five zones. More detailed results of zonal benefits and PJM total benefits are presented in Tables A1-A6 of the Appendix.

4.0 BENEFITS TO CURTAILED LOADS

4.1. Energy Benefits

Participants in curtailment programs save money by eliminating load that they value less than the spot price for energy.[20] We estimate these benefits to be $9-$26 million per year based on the results of the Dayzer simulations and some simplifying assumptions on the economic value customers place on their curtailable load. (Without making those simplifying assumptions, the range of benefits widens from $9-$26 million to $1-$36 million).

The concept is illustrated in Figure 7, which is similar to Figure 6, but with an illustrative "underlying demand curve" added. The underlying demand curve represents customers' reservation prices for delivered energy, which would be the relevant market demand curve if all customers were on real-time pricing programs.[21] With most customers instead on fixed retail prices that do not reflect spot prices, their demand is completely inelastic with respect to spot prices; the market demand curve is distorted into a nearly vertical, inelastic curve, corresponding

[20] Even if the customer is not ordinarily exposed to spot prices, eliminating low-value load creates value. Curtailment programs can provide various mechanisms for customers to capture some of this value.

[21] The exact height and shape of the demand curve would also depend on the way in which transmission and distribution and other charges vary with consumption.

to the "Demand Without Curtailment" line in Figure 7. Curtailment programs add some elasticity to the demand curve, albeit more crudely than real-time pricing programs. The market demand curve becomes the dark black line labeled "e-g-f-h", such that demand is slightly lower when spot prices are high enough to trigger curtailment. Segment "f-g" represents the customers' marginal values of curtailable load.

The benefits to curtailed loads (which might be shared between the customer and their retail provider or curtailment provider) are given by area **aefg**, excluding any necessary equipment costs and the costs of administering the curtailment program. Area **abgf** represents the efficiency gain from not using expensive resources that are more valuable than the curtailable load. Area **abe** represents an increase in consumer surplus and a corresponding decrease in producer surplus. Note that area **bcde** is also labeled in this diagram in order to clarify the differences between the benefits to curtailed loads and benefits to non-curtailed loads. While there is an actual efficiency benefit enjoyed by curtailed loads (as well as an increase in consumer surplus), the consequential increase in consumer surplus to non-curtailed loads is entirely matched by a decrease in producer surplus.

Figure 7. Conceptual Diagram of Energy Benefits to Curtailed Loads

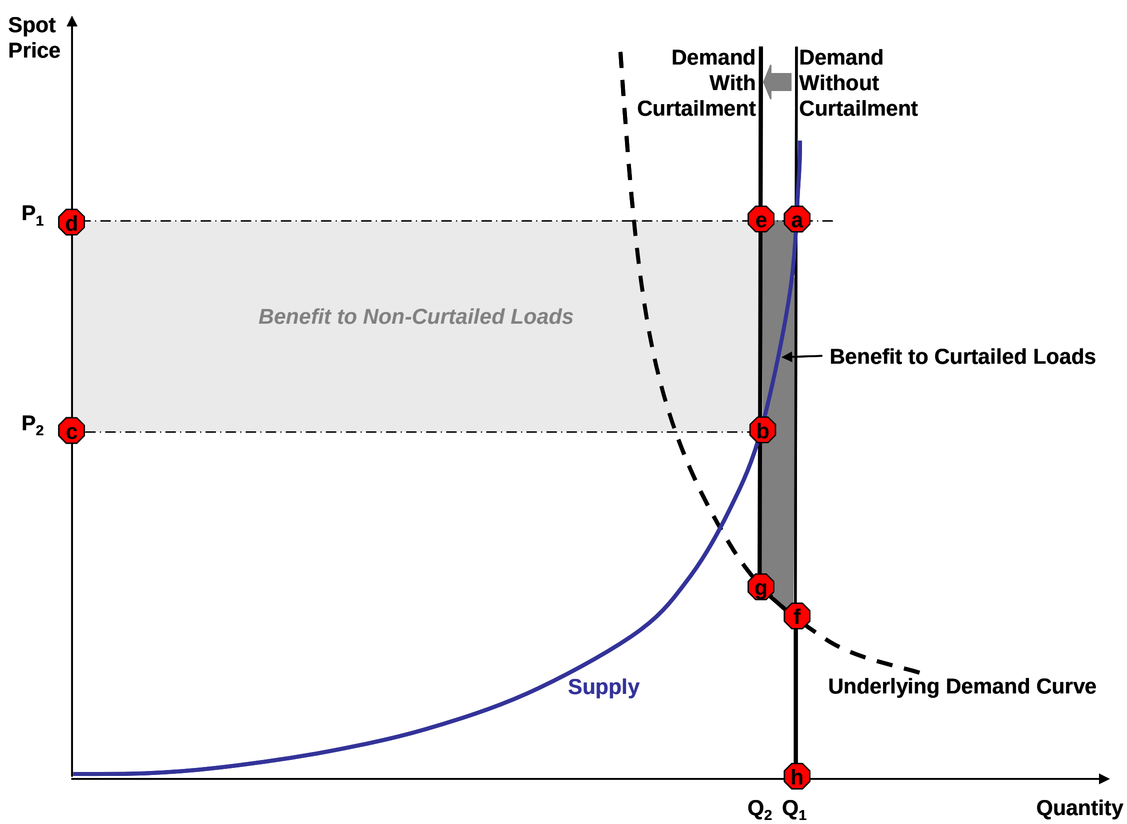


Figure 7 provides a framework for quantifying the energy benefits to curtailed loads, and the Dayzer simulations provide points *a*, *b*, and *e*. *Brattle* made some simplifying assumptions to estimate and bound the price levels of *f* and *g*. The lower bound for *f*-*g* is zero when customers value their curtailable load at zero, for example if customers have been over-air conditioning to the point that building occupants are uncomfortable but not thinking to turn up their thermostats until the curtailment program triggers their interest. The upper bound for *f-g* must be the post-curtailment spot price, P_2, or else the assumed 3% curtailment was too high, such that customers value their curtailed load more than the spot price. An intermediate value can also be estimated by assuming that *f* is given by the minimum retail rate among customer classes, based on the theory that customers consume energy until the marginal value of their least valuable kilowatt-hour equals their retail rate, and the customers with the lowest retail rates have the lowest value marginal uses of energy, and thus are most likely to voluntarily curtail load. Finally, line *f-g* is traced backward from *f* by assuming a typical short-run value of -0.1 for the price elasticity of demand[22] and enforcing that *f-g* does not rise above P_2.

Table 6 summarizes the energy savings to curtailed loads for each reference case. Columns B, C, and D show per megawatt-hour savings corresponding to the lower, intermediate, and upper estimates, respectively. Columns E through G report net savings adjusted for ARR changes. Across the six reference cases, participant savings by the intermediate estimate range from $9 to $26 million.

[22] A Department of Energy report summarizes various estimates of own-price elasticity that range from -0.28 to -0.01. Available at http://www.oe.energy.gov/DocumentsandMedia/congress_1252d.pdf.

Table 6. Energy Benefits to Curtailed Load by State

	Average Curtailed Load (MW) [A]	Benefits to Curtailed Loads ($/MWh) Lower Bound [B]	Intermediate Estimate [C]	Upper Bound [D]	Benefits to Curtailed Loads (Million $) Lower Bound [E]	Intermediate Estimate [F]	Upper Bound [G]
Actual Peak (AP) Case							
PA	**236**	**$15**	**$114**	**$178**	**$0.4**	**$2.7**	**$4.2**
NJ	**289**	**$15**	**$73**	**$183**	**$0.4**	**$2.1**	**$5.3**
DE	**78**	**$19**	**$127**	**$190**	**$0.2**	**$1.0**	**$1.5**
MD	**355**	**$13**	**$111**	**$189**	**$0.5**	**$3.9**	**$6.7**
DC	**56**	**$12**	**$111**	**$194**	**$0.1**	**$0.6**	**$1.1**
MADRI Total	**1,014**	**$15**	**$102**	**$185**	**$1.5**	**$10.4**	**$18.8**
Normalized (N) Case							
PA	**246**	**$18**	**$149**	**$213**	**$0.4**	**$3.7**	**$5.2**
NJ	**306**	**$18**	**$100**	**$211**	**$0.5**	**$3.1**	**$6.5**
DE	**79**	**$26**	**$155**	**$218**	**$0.2**	**$1.2**	**$1.7**
MD	**371**	**$18**	**$137**	**$216**	**$0.7**	**$5.1**	**$8.0**
DC	**58**	**$18**	**$140**	**$223**	**$0.1**	**$0.8**	**$1.3**
MADRI Total	**1,060**	**$18**	**$131**	**$214**	**$2.0**	**$13.8**	**$22.7**
High Peak (HP) Case							
PA	**259**	**$34**	**$259**	**$323**	**$0.9**	**$6.7**	**$8.4**
NJ	**324**	**$31**	**$198**	**$310**	**$1.0**	**$6.4**	**$10.1**
DE	**83**	**$42**	**$280**	**$343**	**$0.3**	**$2.3**	**$2.8**
MD	**392**	**$28**	**$235**	**$314**	**$1.1**	**$9.2**	**$12.3**
DC	**62**	**$25**	**$243**	**$326**	**$0.2**	**$1.5**	**$2.0**
MADRI Total	**1,120**	**$31**	**$234**	**$318**	**$3.5**	**$26.2**	**$35.6**
Low Peak (LP) Case							
PA	**230**	**$10**	**$105**	**$169**	**$0.2**	**$2.4**	**$3.9**
NJ	**290**	**$11**	**$58**	**$168**	**$0.3**	**$1.7**	**$4.9**
DE	**74**	**$12**	**$103**	**$166**	**$0.1**	**$0.8**	**$1.2**
MD	**350**	**$9**	**$90**	**$169**	**$0.3**	**$3.2**	**$5.9**
DC	**55**	**$8**	**$87**	**$170**	**$0.0**	**$0.5**	**$0.9**
MADRI Total	**999**	**$10**	**$85**	**$169**	**$1.0**	**$8.5**	**$16.8**
High Fuel (HF) Case							
PA	**246**	**$23**	**$191**	**$255**	**$0.6**	**$4.7**	**$6.3**
NJ	**306**	**$24**	**$142**	**$253**	**$0.7**	**$4.4**	**$7.7**
DE	**78**	**$31**	**$198**	**$261**	**$0.2**	**$1.6**	**$2.0**
MD	**370**	**$22**	**$178**	**$257**	**$0.8**	**$6.6**	**$9.5**
DC	**58**	**$21**	**$178**	**$262**	**$0.1**	**$1.0**	**$1.5**
MADRI Total	**1,059**	**$23**	**$172**	**$256**	**$2.5**	**$18.2**	**$27.1**
Low Fuel (LF) Case							
PA	**244**	**$16**	**$113**	**$177**	**$0.4**	**$2.8**	**$4.3**
NJ	**306**	**$16**	**$66**	**$175**	**$0.5**	**$2.0**	**$5.4**
DE	**78**	**$23**	**$120**	**$183**	**$0.2**	**$0.9**	**$1.4**
MD	**371**	**$16**	**$100**	**$178**	**$0.6**	**$3.7**	**$6.6**
DC	**58**	**$16**	**$103**	**$186**	**$0.1**	**$0.6**	**$1.1**
MADRI Total	**1,058**	**$16**	**$95**	**$178**	**$1.7**	**$10.0**	**$18.8**

Notes:
[E], [F], [G]: Benefits are net of changes in ARR value.
[B] = [E] / ([A] x 100 Hours). Similar formula applies for [C] and [D].

4.2. Capacity Benefits

Customers who agree to have their load curtailed during peak periods flatten the load shape of the market overall. This reduces the amount of generation capacity needed to meet reserve adequacy requirements and avoids the need to build peaking plants to serve just a few hours of (curtailable) peak load. This benefit will be enjoyed by program participants in the form of reduced capacity payments or demand charges, assuming that curtailable load is dependably curtailable and "counts" as a capacity resource or that it is not required to purchase installed capacity (ICAP) in order to comply with resource adequacy requirements. A rough measure of such a benefit is the $58/kW-yr levelized cost of new capacity that PJM has used to set its capacity deficiency payments.[23] Applying $58/kW-yr to the 1,101 MW reduction in peak load in the Normalized Case plus an avoided reserve margin of 15% yields a $73 million annual benefit to participating loads.[24] Benefits would be nearly proportionately higher if more peak load were curtailed. Clearly, there is substantial value available, but that value can be captured only to the extent that adequate DR programs are in place.

Capacity benefits could be quantified more rigorously by forecasting capacity prices for each zone and over time, based on PJM's new Reliability Pricing Model (RPM).[25] Although most of PJM currently has a surplus of capacity today, causing low capacity prices, any zones suffering from a shortage of capacity (including imports) would have correspondingly high capacity prices.

In the long term, a reasonably unbiased expectation is for all market areas to eventually reach equilibrium. On that timescale, capacity prices might not necessarily be $58/kW-yr, which is based on a new combustion turbine's fixed costs, including levelized capital costs. It is likely that the technologies that set capacity prices (e.g. their characteristics, costs, and expected energy margins) will change over time, particularly if new technologies and resource options develop, for example if DR resources become available more widely.

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[23] PJM's Capacity Deficiency Rate is currently set at $160/MW-day (= 58.4 $/kW-Yr) based on the all-in levelized cost of a combustion turbine. (See Schedule 11 of the PJM Tariff at.http://www.pjm.com/committees/tac/downloads/20050829-item-5a-dsr-schedule-11.pdf).

[24] PJM requires a reserve margin of 15%. See *Summer 2006 PJM Reliability Assessment*, May 24, 2006.

[25] Available at http://www.pjm.com/committees/working-groups/pjmramwg/pjmramwg.html.

5.0 FACTORS NOT QUANTIFIED IN THIS STUDY

5.1. Benefits not Quantified

Important benefits of demand curtailment that have not been quantified in this study include enhanced market competitiveness, reduced price volatility, the provision of insurance against extreme events, the option to curtail some load in the volatile real-time market, reduced capacity market prices, and deferred T&D costs.

Enhanced Market Competitiveness

Many market observers have noted that, particularly during high-load periods, electricity markets suffer from structural problems that increase the incentive and ability for generators to exercise market power, including the fact that most customers are not exposed directly to spot prices, so they have no incentive to reduce even their lowest-value consumption when spot prices spike to $1,000 per megawatt-hour. Because of this regulatory construct, the market demand curve is almost completely inelastic. Expanding DR programs, including curtailment programs, would increase the elasticity of demand and thereby increase the competitiveness of the market. Simple game-theoretic models suggest that doubling the elasticity of demand – not an overly-ambitious goal, given the nascence of DR programs – would enhance competitiveness as effectively as a 50% reduction in market concentration would. Enhanced competitiveness could result in lower energy prices and lower capacity prices both in the short term and the long term.

Reduced Price Volatility

Many customers are risk-averse and value rate stability, for example because they need to be able to forecast their costs accurately for budgeting purposes. Yet retail rates can fluctuate in response to spot prices (for customers on real-time pricing) or expected wholesale prices (for other customers). To the extent that demand curtailment reduces volatility in the spot market, it improves rate stability for at least some customers. Our estimated benefits to non-curtailed loads, which are based on reductions in average prices, are incomplete measures of value because they do not account for the value of reducing the price *variance* faced by customers.

Insurance Against Extreme Events

The observation that benefits of demand curtailment in the High Peak Case exceed those in the Normalized Case more than the benefits in Normalized Case exceed those in the Low Peak Case suggests that demand curtailment has disproportionately more value under tighter market conditions. This is the reason for analyzing multiple scenarios instead of analyzing a single normalized scenario. However, most studies, including ours, analyze only a small number of plausible scenarios. There are many possible events that, even though fairly unlikely individually, would likely reduce the risk of high-cost outcomes and could add disproportionately to the overall probability-weighted value of curtailment. Such events include the coincident outages of major generators and transmission lines or extreme heat waves occurring in shoulder months when many generators are on maintenance. The value of demand curtailment could be quantified more completely by simulating such extreme, low-probability events.

Real-Time Curtailments

Dayzer and other similar models lack surprises in demand and supply conditions and the resulting price volatility that characterizes real-time markets.[26] Therefore, the simulated prices are more comparable to day-ahead prices, and this study must be considered an analysis of day-ahead curtailment programs. It does not capture the higher value of being able to curtail demand in the more volatile real-time market, when market conditions can become tight unexpectedly.

A recent analysis by PJM demonstrates the potentially large market impact of real-time curtailment.[27] PJM estimated that load reductions during the heat wave in August of 2006 reduced real-time prices by more than $300 per megawatt-hour during the highest usage hours, estimated to be equivalent to more than $650 million in payments for energy. This impact was very large for several reasons: demand reductions reached 2,000 MW (compared to approximately 1,100 MW in this study), they occurred in real-time, and because of the particular way PJM modeled the effect of curtailment. PJM simply re-ran its actual real-time software with 2,000 MW (that had actually been curtailed day-ahead) added back to the load in real time, without having committed additional capacity to serve that additional load. This left the modeled real-time market with insufficient capacity, forcing PJM's analysis to rely on very high-cost generation. Nevertheless, PJM's analysis suggests that load curtailment can have the greatest price impact when the curtailable resources are "dispatchable" in real-time under unexpectedly tight market conditions, such as when load has been under-forecast or when multiple generators trip offline.

Capacity Market Benefits to Non-Curtailed Load

The effects of demand response on energy prices are often discussed, but the potential effects on capacity prices are rarely mentioned. Demand response could reduce capacity prices by reducing peak loads and therefore reducing the demand for capacity, as determined by PJM's resource adequacy requirements. If the demand for capacity is reduced, then the capacity market could clear at a lower price, particularly if the demand reduction shifts the market balance from a capacity scarcity to a capacity surplus. Any resulting change in capacity price would apply to the entire non-curtailed load, yielding a potentially very large benefit.

In the long run, when new physical capacity is needed, however, the capacity price is likely to be set by the long-run marginal cost of new capacity and will hence be less sensitive to small reductions in demand. Even then, capacity prices could be lower with demand response than

[26] Although generator outages, transmission outages, and load spikes are included in the model, they do not occur as a surprise. The model commits capacity given advance knowledge of all market conditions.
[27] See http://pjm.com/contributions/news-releases/2006/20060817-demand-response-savings.pdf

without because the long-run capacity supply curve is not completely flat. The long-run capacity supply curve is likely to be slightly sloped because not all marginal new capacity has the same cost due to diversity of site characteristics, technology and plant configurations, and developers' cost structures.

Delay of Transmission and Distribution Investments

Reducing peak loads by 3% is comparable to two years of load growth on average and possibly much more in certain locations. In some circumstances, reducing peak loads could enable utilities to delay upgrading distribution transformers and other T&D equipment that is stressed by peak loads.

5.2. Offsetting Market Effects Not Quantified

This study provides quantitative estimates in response to the question posed by MADRI and PJM: What is the direct effect of demand curtailment on energy prices and resulting benefits to non-curtailed loads? However, there are several short-term and long-term offsets to the quantified benefits.

Short-Term Offsets

First, customers participating in DR programs might shift some of their curtailed load to other hours. Such load shifting could reduce the market impact of curtailment by increasing prices and emissions in non-peak hours. However, the level of offsets depends on how much and to which hours the customer shifts load. The offsetting effect is likely to be small if consumption is shifted to off-peak hours. Second, price reductions resulting from demand curtailment could dampen the extent to which other customers respond to high market prices. Customers on real-time prices limit their response when they see a decrease in spot prices. Since these dynamic interactions of prices and loads are not considered in our simulation analyses, prices could consequently increase slightly relative to our estimates until a new equilibrium of demand and supply is reached in response to these price changes.[28] (Note, however, that as the number of customers on real-time prices increases, the total demand response to high spot prices will increase, resulting in a larger overall reduction in peak demand and market prices.) Third, reductions in energy prices could result in some generators earning insufficient revenues to cover their bid costs, resulting in higher uplift payments. While the overall magnitudes of these offsets may be small, they reflect the dynamic interactions of demand and supply that are not explored in our more static market simulation analysis.

[28] Evidence of load shifting and real-time price responsiveness is provided in "Assessment of Customer Response to Real Time Pricing -- Task 2: Wholesale Market Modeling of New Jersey and PJM" by the Center for Economic & Environmental Policy, Edward J. Bloustein School of Planning and Public Policy at Rutgers University, November 11, 2005.

Longer-Term Offsets

To expect the estimated benefits to non-curtailed loads to persist is like assuming one could permanently reduce prices by building a particular power plant. In the long run, under a competitive market equilibrium, the new plant will likely displace another plant, leading to the same supply and demand balance and potentially the same market prices as if the particular plant had not been built.

Curtailable demand is similar to physical peaking capacity. In the long run, reduced market prices and the associated reduction in producer surplus could induce the retirement of marginal capacity and the delay of new capacity additions. Such a response could increase energy prices, partially offsetting some of the benefits to non-curtailed load that have been quantified in this study. These offsets could occur quickly if increased DR quickly induces plant retirements.

The estimated energy market benefit to non-curtailed loads is likely to be further offset by increases in capacity prices. To the extent that suppliers of marginal capacity expect to earn less in the energy market, they may bid higher prices into the capacity market in order to cover their fixed costs. For example, power plants that are candidates for retirement will stay online only if they expect to recover their fixed "to-go" costs through a combination of energy margins and revenues for providing ancillary services and capacity. Similarly, potential new entrants will build new capacity only if they expect to recover their long-run marginal cost of building and operating new capacity.[29] Hence, a reduction in energy margins must be expected to be offset by increases in capacity payments in the long run, assuming a competitive market equilibrium. Again, these "long-term" offsets may occur fairly quickly if expectations for reduced energy margins work their way quickly into bids for providing capacity.

It is possible to estimate capacity online and capacity prices in the short- to medium-term (i.e., 1-3 years), when the market is in a known deviation from equilibrium and any new capacity coming online is already under construction (retirement decisions are more difficult to predict). However, it is more difficult to foresee exactly how and when the population of generation capacity will change in the future, where new plants will be built, when boom-bust cycles in capacity will occur, what technology will set the price for capacity, and what capacity prices will be in the long-term future. Under such uncertainty, detailed analyses are less useful, and broad-brush assumptions become more necessary. The most economically defensible broad-brush assumption is not to ignore the possibility that capacity and capacity prices will change in response to increase DR – that would be to assume that generators would perpetually keep money-losing plants online, or that they would over-invest in new capacity, earning less than their cost of capital. An unbiased, standard economic assumption is that the market will reach an equilibrium in which generators earn their cost of capital, neither more nor less in expectations, such that there would be significant offsets to the energy benefits calculated from the static analysis of this study.

[29] See "Demand Response Is Important—But Let's Not Oversell (or Over-Price) It," Steven D. Braithwait, *The Electricity Journal*, Volume 16, Issue 5, June 2003, pages 52-64, for a discussion of the "dynamic effects of price expectations on generators' investment behavior."

Ultimately, the long-term benefits will be determined by the extent to which adding demand response to the resource mix lowers total resource costs. Although the energy and capacity-related effects quantified in this study are related to resource costs (such as the cost of a new peaking unit), a comprehensive analysis of total resource costs, including an assessment of the likely technology mix of future capacity and demand response resources, is a question that has not been addressed in this study. Adding DR to the long-term resource mix could, for example, lower the long-term marginal cost of capacity.

In any timeframe, a more comprehensive analysis would also have to consider the competitiveness effects discussed in Section 5.1. DR will have the greatest value in markets that are not in a competitive equilibrium because they are temporarily tight or in structurally less competitive market areas that may also suffer from barriers to entry. In such cases, demand curtailment could enhance the competitiveness of both energy and capacity markets. Indeed, the market impacts of demand curtailment are likely to be the greatest and most enduring not where markets are working well, but where competition is limited.

5.3. Environmental Implications

Demand reductions during periods of peak load could achieve environmental benefits by reducing generation of the dirtiest plants in load centers on the hottest, smoggiest days. However, this study has not attempted to estimate this environmental benefit of demand curtailment. In addition, offsetting shifts in load and generation are likely to consume most or all of the temporary savings.

The most important offset comes from shifts in the cap-and-trade markets. NOx and SOx emissions (and soon CO_2 in states that have signed the Regional Greenhouse Gas Initiative) are determined by the regulatory cap, such that a temporary decrease in emissions liberates allowances which could be used by others either locally or elsewhere in the regional/national cap-and-trade region.[30]

Similarly, some units' emissions are limited by maximum-run-hour constraints or by emissions limits imposed by their environmental permits. Reducing generation in one period could allow these units to run more in other periods if economic.

An additional offset occurs because some participants in curtailment programs do not actually curtail their load but instead run behind-the-meter distributed generation (DG), which could be dirtier than the market generation it displaces if it is not pollution-controlled. Moreover, if the DG units are less than 25 MW, they are not subject to the market-wide cap-and-trade program, so running DG could increase total market-wide emissions.

[30] See "Is Real-Time Pricing Green?: The Environmental Impacts of Electricity Demand Variance," Stephen P. Holland and Erin T. Mansur, The Center for the Study of Energy Markets (CSEM) at the University of California Energy Institute, August 2004. Holland and Mansur estimated the impact of reductions in "load volatility" on emissions, but they note that their estimated increases and decreases in emissions would not result in a net change in emissions where emissions are regulated by cap-and-trade programs (p. 26).

Even if there were no offsets, e.g., for mercury in the near term, a 3% reduction in generation in 1% of hours reduces total generation by only 0.03%, assuming, unrealistically, that there are no shifts in load to coal-dominated off-peak hours and no increases in consumption among price-responsive customers. The associated reduction in emissions would be similarly small. There would not be a disproportionate impact like there is with energy prices, which are affected by the extreme steepness of the bid offer curve in tight periods and the fact that the price reduction affects the entire market, not just the marginal generation.

6.0 CONCLUSIONS

This study demonstrates that even a modest 3% load reduction in each of five PJM zones' 100 super-peak hours, amounting to 0.9% of PJM's peak load, would have substantial energy and capacity market benefits to both curtailed and non-curtailed loads.

- Spot prices would be reduced by 5-8% during curtailed hours, resulting in a $57-$182 million short-term annual benefit to non-curtailed loads in the five MADRI states (adjusted for changes in ARR/FTR value). The system-wide benefits to PJM loads range from $65 to $203 million. More widespread participation in DR and deeper curtailments would result in even greater price impacts; less widespread participation results in substantially less benefit in each zone, suggesting that a regional approach to promoting DR is warranted.

- Curtailed loads would save $9-$26 million in energy ($85-$234 per megawatt-hour for the roughly 1,100 MW curtailed for 100 hours) and $73 million in capacity (at $58 per kW-yr of curtailable load), excluding equipment costs and the costs of administering a demand response program. These benefits would be recurring and would not be reduced by the offsetting effects discussed in Section 5.2, but they are calculated based on a rough proxy for the value of capacity, whereas the actual capacity price would vary over time and by location.

This study does not quantify several potentially large benefits of DR, including enhanced market competitiveness, reduced price volatility, insurance against extreme events, the option to curtail some load in the volatile real-time market, reduced capacity market prices affecting all load, and deferred T&D costs.

We also have not quantified offsetting effects that would likely reduce the quantified benefits to non-curtailed load energy market impacts in the long term. The long-term benefits of demand curtailment cannot be measured fully by this type of analysis. The long-term benefit will be determined by the extent to which adding DR to the resource mix lowers total resource costs.

Future research could include estimation of the additional benefits and offsets in the medium term, a long-term resource cost analysis, and an analysis of how customer participation and benefits depend on the design of demand response programs. MADRI and PJM could also build on the present study by incorporating learnings about program design from other market areas and simulating the market under various types of programs.

ABOUT THE AUTHORS

This report was prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI) by Samuel Newell and Frank Felder, with research assistance by Yuan Mei and with advice from Johannes Pfeifenberger and Ahmad Faruqui. Sam Newell is a Principal at *The Brattle Group,* where he focuses on energy market analysis, transmission project evaluation, generation asset valuation, and energy contracts. Frank A. Felder is the Director of the Center for Energy, Economic & Environmental Policy at Rutgers University and a Senior Advisor of *The Brattle Group*.

Appendix

Figure A-1. Impact of Load Curtailment on Prices at PJM Eastern Hub (AP Case)

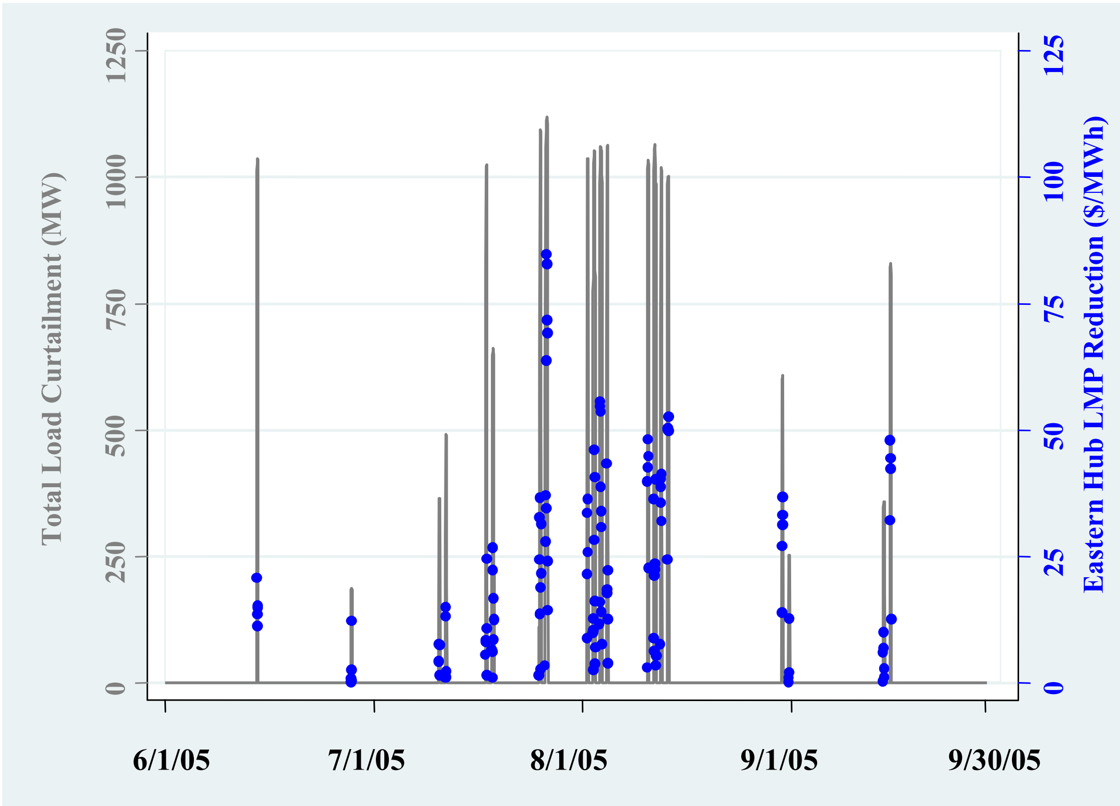

Figure A-2. Impact of Load Curtailment on Prices at PJM Eastern Hub (Normalized Case)

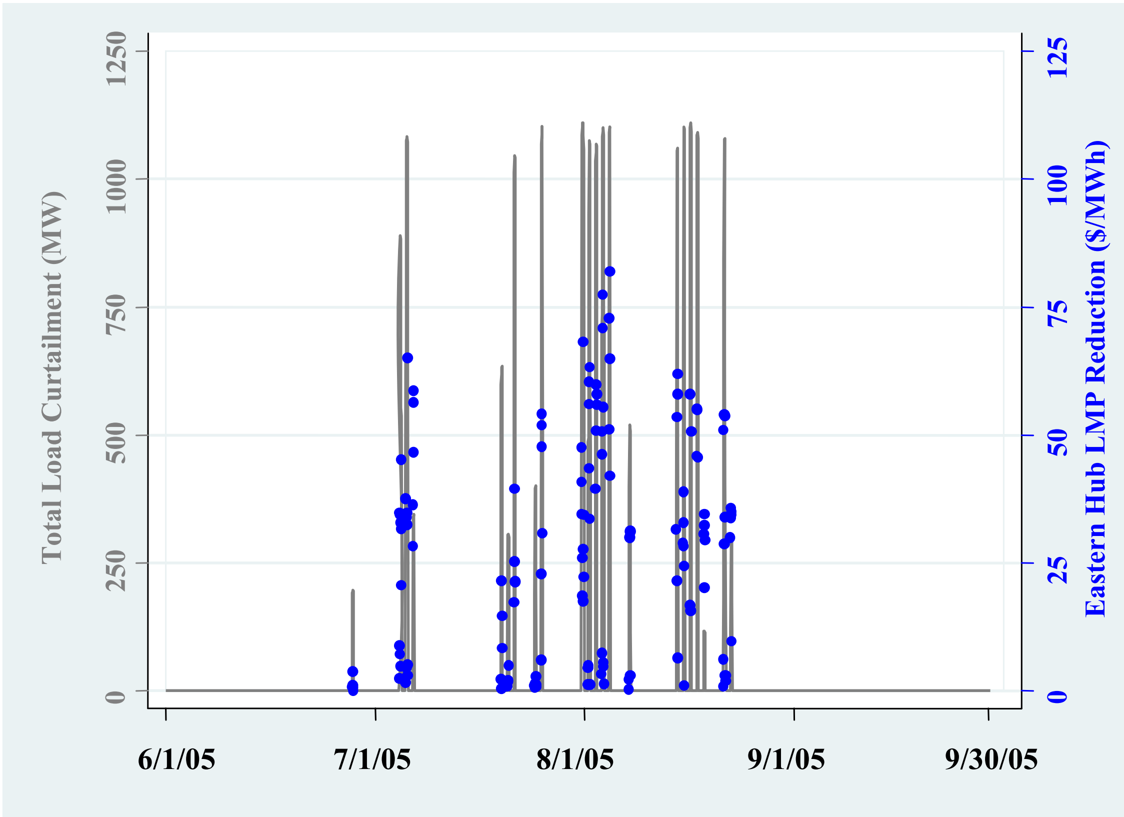

Figure A-3. Impact of Load Curtailment on Prices at PJM Eastern Hub (HP Case)

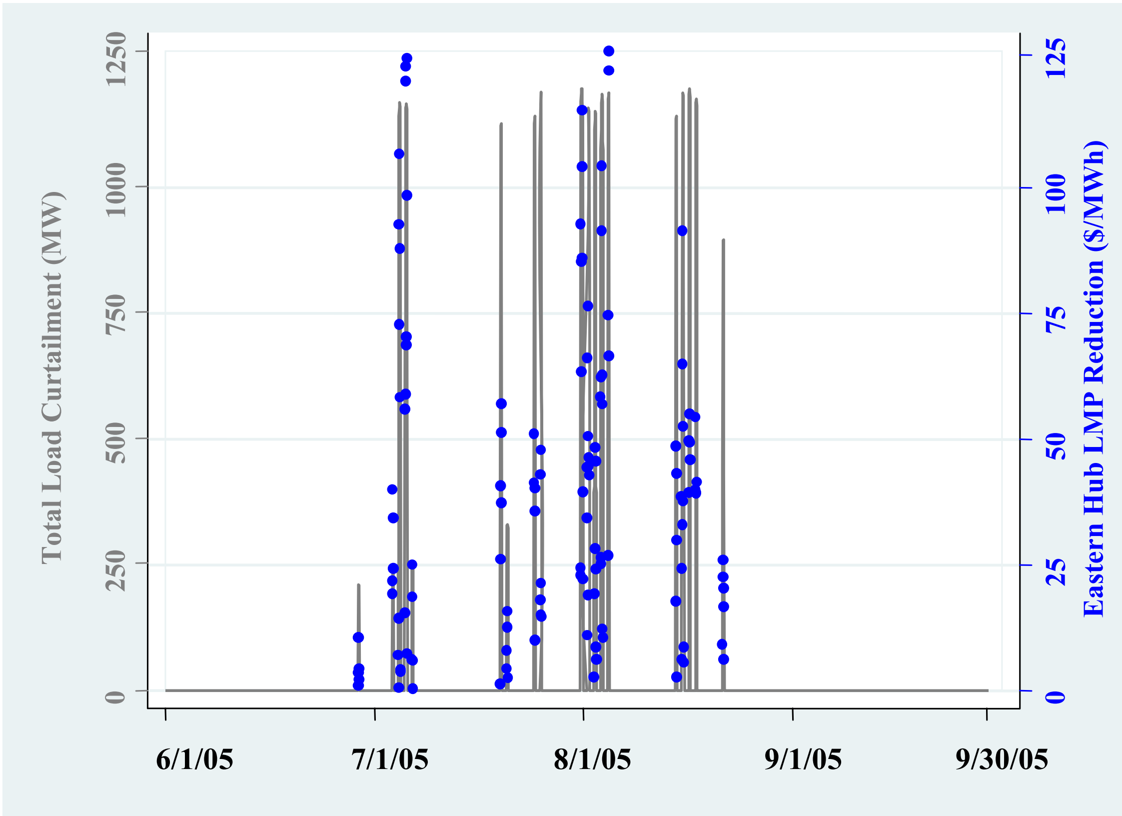

Figure A-4. Impact of Load Curtailment on Prices at PJM Eastern Hub (LP Case)

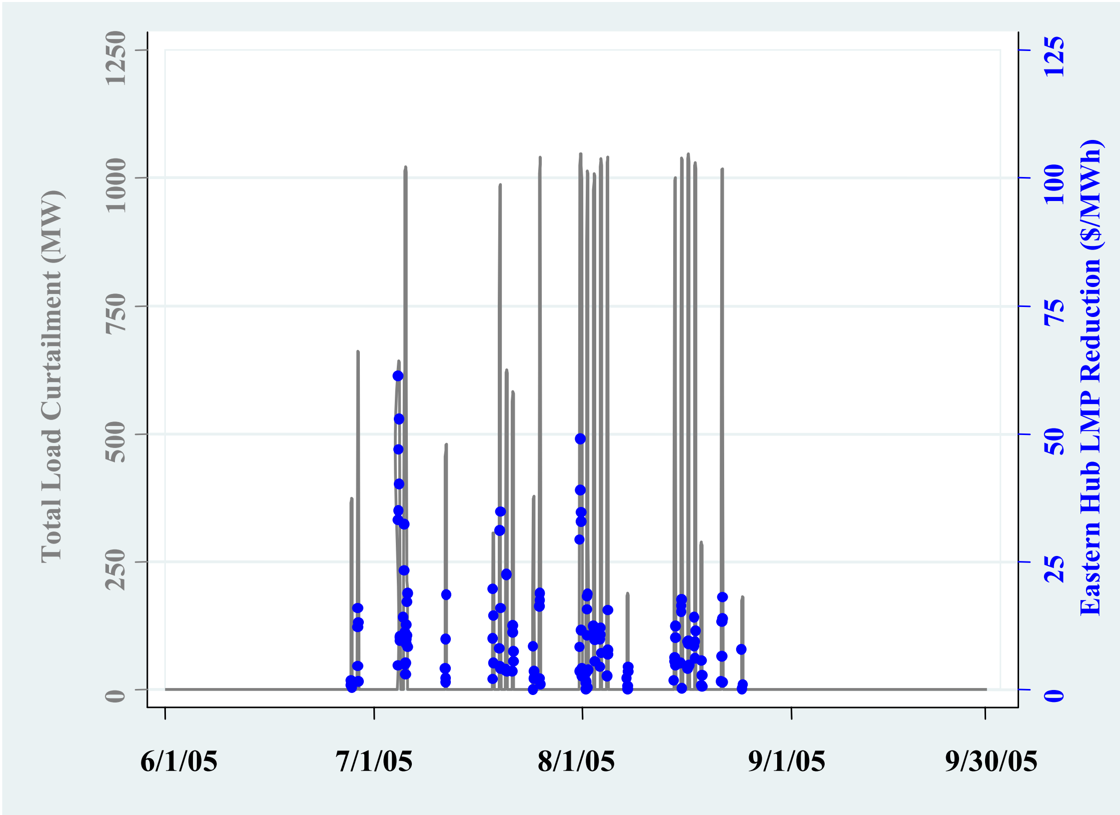

Figure A-5. Impact of Load Curtailment on Prices at PJM Eastern Hub (HF Case)

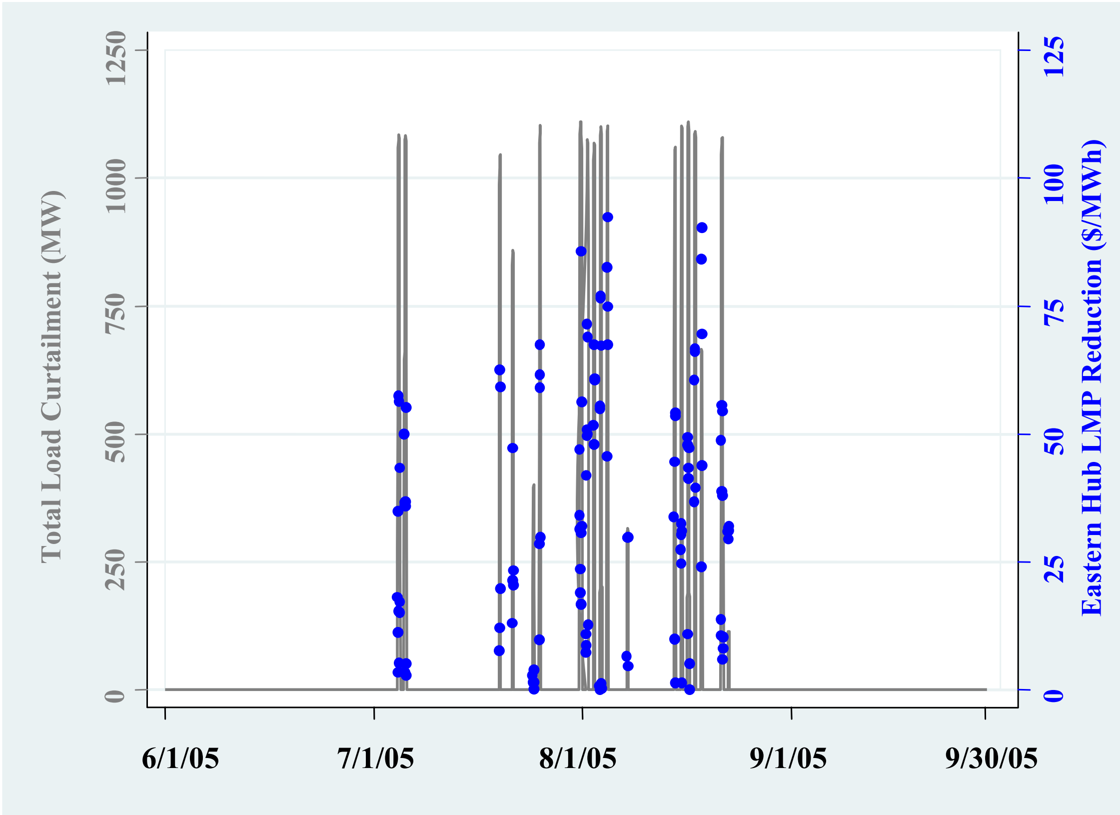

Figure A-6. Impact of Load Curtailment on Prices at PJM Eastern Hub (LF Case)

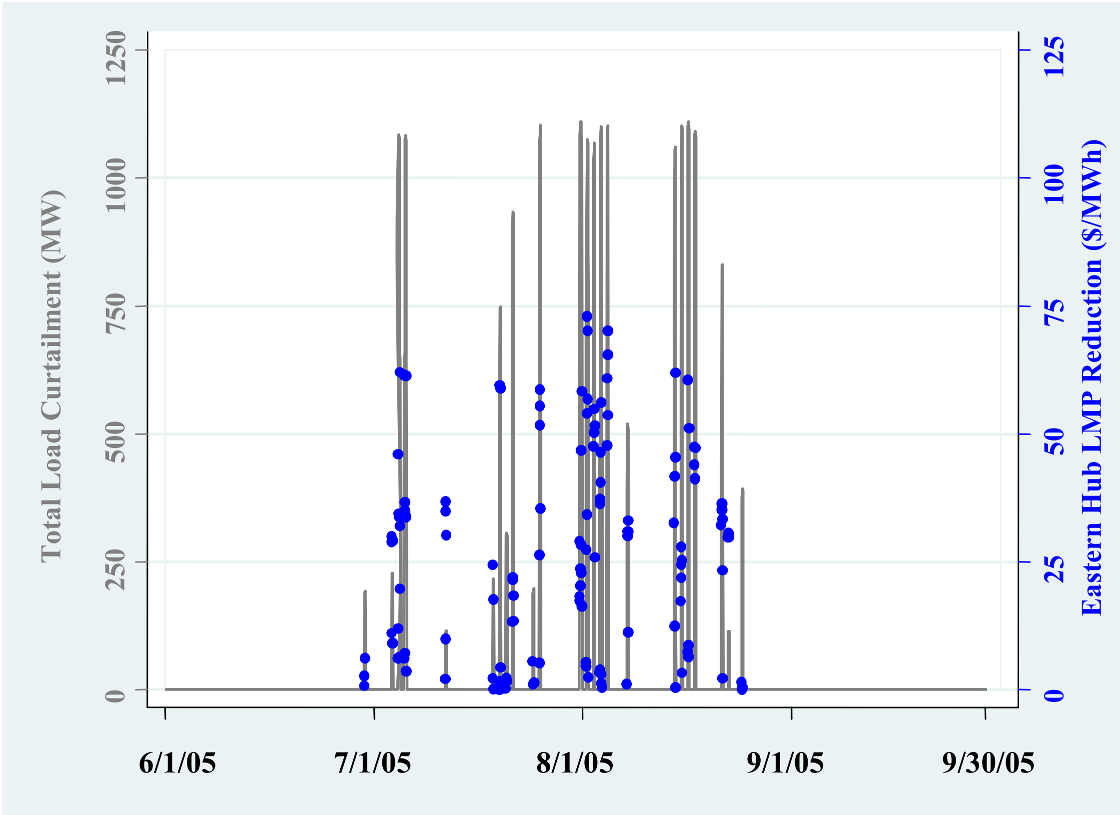

Table A-1. Price Impacts and Benefits to Non-Curtailed Loads, Actual Peak (AP) Case

Zone	MADRI	Curtailment Impacts During 137 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$11	6%	142	2.2%	6,227	$9.5	($0.9)	$8.7
DPL	DE/MD**	$21	10.6%	83	2.2%	3,623	$10.6	($2.4)	$8.3
PECO	PA	$15	7.8%	172	2.2%	7,531	$15.5	($2.8)	$12.7
PEPCO	DC/MD**	$13	6.0%	135	2.2%	5,940	$10.2	($2.8)	$7.4
PSEG	NJ	$13	7.2%	211	2.2%	9,303	$17.1	($1.3)	$15.7
AECO	NJ	$10	4.7%	-	-	2,498	$3.3	$0.2	$3.5
JCPL	NJ	$12	6.8%	-	-	5,481	$9.3	($0.4)	$8.9
DUQ	PA	$2	1.6%	-	-	2,560	$0.7	($0.0)	$0.7
METED	PA	$13	6.6%	-	-	2,611	$4.6	($0.6)	$4.0
PENELEC	PA	$6	4.1%	-	-	2,626	$2.3	($0.3)	$2.0
PPL	PA	$12	6.6%	-	-	6,729	$10.9	($0.7)	$10.2
APS	PA/MD**	$6	3.5%	-	-	8,094	$6.4	($4.3)	$2.0
RECO	NY	$10	5.9%	-	-	358	$0.5	$0.0	$0.5
AEP	-	$1	1.3%	-	-	20,867	$4.3	($0.9)	$3.3
DAY	-	$1	1.2%	-	-	3,064	$0.6	($0.0)	$0.6
DOM	-	$2	1.6%	-	-	16,741	$5.1	($1.2)	$3.9
COMED	-	$1	1.2%	-	-	16,806	$3.3	($0.0)	$3.3
Total in Curtailed Zones		$14	7.2%	743	2.2%	32,626	$62.9	($10.2)	$52.7
Total in Non-Curtailed Zones		$4	2.6%	0	0.0%	88,435	$51.3	($8.4)	$42.9
Total by State	PA	$11	5.8%	172	0.7%	25,514	$36.7	($6.3)	$30.4
	NJ	$13	6.7%	211	1.2%	17,282	$29.7	($1.6)	$28.1
	DE	$21	10.6%	57	2.2%	2,482	$7.3	($1.6)	$5.7
	MD	$12	6.0%	259	2.0%	12,886	$20.8	($4.3)	$16.5
	DC	$13	6.0%	41	2.2%	1,791	$3.1	($0.9)	$2.2
MADRI Total		$12	6.7%	740	1.2%	59,955	$97.5	($14.7)	$82.9
Non-MADRI Total		$2	3.1%	3	0.0%	61,106	$16.7	($3.9)	$12.8
Total PJM		$7	3.9%	743	0.6%	121,061	$114.2	($18.6)	$95.7

Notes:

[A] and [B]: LMP reduction is weighted by hourly residual load.

[F] = [A] x [E] x number of hours with at least one zone curtailed.

[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.

[H] = [F] + [G].

Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-2. Price Impacts and Benefits to Non-Curtailed Loads, Normalized (N) Case

Zone	MADRI	Curtailment Impacts During 147 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$13	6%	139	2.1%	6,585	$12.8	($0.6)	$12.1
DPL	DE/MD**	$27	11.9%	78	2.1%	3,702	$14.6	($4.0)	$10.6
PECO	PA	$16	7.4%	167	2.1%	7,906	$18.3	($3.4)	$14.9
PEPCO	DC/MD**	$17	7.1%	132	2.1%	6,223	$16.0	($4.4)	$11.6
PSEG	NJ	$14	6.8%	208	2.1%	9,759	$20.5	($1.1)	$19.4
AECO	NJ	$12	4.8%	-	-	2,564	$4.3	$0.1	$4.5
JCPL	NJ	$13	6.5%	-	-	5,631	$11.1	($0.6)	$10.4
DUQ	PA	$1	0.5%	-	-	2,761	$0.3	($0.0)	$0.3
METED	PA	$14	5.9%	-	-	2,602	$5.2	($0.7)	$4.5
PENELEC	PA	$7	3.4%	-	-	2,660	$2.6	($0.4)	$2.1
PPL	PA	$13	5.9%	-	-	6,961	$12.8	($1.2)	$11.6
APS	PA/MD**	$6	3.1%	-	-	8,303	$7.4	($7.0)	$0.4
RECO	NY	$10	5.4%	-	-	401	$0.6	$0.0	$0.7
AEP	-	$1	0.5%	-	-	21,250	$2.3	($0.8)	$1.5
DAY	-	$1	0.5%	-	-	3,010	$0.3	($0.0)	$0.3
DOM	-	$2	1.5%	-	-	17,033	$6.2	($1.7)	$4.5
COMED	-	$1	0.7%	-	-	18,168	$2.5	($0.0)	$2.5
Total in Curtailed Zones		$16	7.4%	724	2.1%	34,176	$82.1	($13.5)	$68.5
Total in Non-Curtailed Zones		$4	2.1%	0	0.0%	91,343	$55.7	($12.4)	$43.3
Total by State	PA	$11	5.2%	167	0.6%	26,435	$42.4	($8.8)	$33.6
	NJ	$14	6.4%	208	1.1%	17,954	$35.9	($1.6)	$34.3
	DE	$27	11.9%	53	2.1%	2,537	$10.0	($2.7)	$7.2
	MD	$15	6.4%	252	1.8%	13,501	$29.3	($6.1)	$23.2
	DC	$17	7.1%	40	2.1%	1,877	$4.8	($1.3)	$3.5
MADRI Total		$13	7.1%	721	1.1%	62,304	$122.4	($20.5)	$101.9
Non-MADRI Total		$2	2.6%	3	0.0%	63,216	$15.4	($5.4)	$9.9
Total PJM		$7	3.6%	724	0.6%	125,519	$137.8	($26.0)	$111.8

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-3. Price Impacts and Benefits to Non-Curtailed Loads, High Peak (HP) Case

Zone	MADRI	Curtailment Impacts During 133 Hours w/ At Least One Zone Curtailing: Weighted Average LMP Reduction ($/MWh) [A]	Weighted Average LMP Reduction (%) [B]	Average Load Curtailment (MW) [C]	Average Load Curtailment (%) [D]	Average Residual Load (MW) [E]	Gross Benefits (Million $) [F]	ARR Change (Million $) [G]	Net Benefits (Million $) [H]
BGE	MD	$24	8%	162	2.3%	6,960	$22.5	($2.3)	$20.2
DPL	DE/MD**	$37	10.4%	91	2.3%	3,894	$19.2	($1.8)	$17.4
PECO	PA	$42	11.6%	195	2.3%	8,399	$46.4	($15.3)	$31.1
PEPCO	DC/MD**	$25	7.8%	154	2.3%	6,578	$22.3	($4.6)	$17.7
PSEG	NJ	$26	8.2%	244	2.3%	10,401	$36.3	($1.1)	$35.2
AECO	NJ	$31	8.0%	-	-	2,716	$11.0	($0.3)	$10.8
JCPL	NJ	$24	7.7%	-	-	6,035	$19.5	($1.0)	$18.5
DUQ	PA	$2	0.9%	-	-	2,972	$0.8	($0.1)	$0.8
METED	PA	$22	6.4%	-	-	2,765	$8.0	($1.0)	$7.0
PENELEC	PA	$17	4.7%	-	-	2,840	$6.2	($1.3)	$5.0
PPL	PA	$19	6.3%	-	-	7,406	$18.7	($1.6)	$17.1
APS	PA/MD**	$9	3.1%	-	-	8,843	$10.3	($6.3)	$4.0
RECO	NY	$18	6.2%	-	-	429	$1.0	$0.1	$1.2
AEP	-	$2	1.0%	-	-	22,718	$7.0	($4.9)	$2.1
DAY	-	$0	0.0%	-	-	3,231	$0.0	($0.1)	($0.1)
DOM	-	$6	2.4%	-	-	18,028	$13.9	($1.6)	$12.3
COMED	-	$1	0.6%	-	-	19,877	$2.7	($0.1)	$2.7
Total in Curtailed Zones		$30	9.1%	845	2.3%	36,231	$146.6	($25.0)	$121.6
Total in Non-Curtailed Zones		$8	2.6%	0	0.0%	97,861	$99.2	($18.0)	$81.2
Total by State	PA	$23	6.7%	195	0.7%	28,158	$84.5	($21.9)	$62.6
	NJ	$26	8.0%	244	1.3%	19,152	$66.8	($2.4)	$64.5
	DE	$37	10.4%	62	2.3%	2,668	$13.1	($1.2)	$11.9
	MD	$24	7.4%	295	2.0%	14,277	$45.3	($7.2)	$38.1
	DC	$25	7.8%	46	2.3%	1,984	$6.7	($1.4)	$5.3
MADRI Total		$25	7.9%	842	1.3%	66,238	$216.5	($34.0)	$182.4
Non-MADRI Total		$3	3.4%	3	0.0%	67,854	$29.4	($9.0)	$20.3
Total PJM		$14	4.3%	845	0.6%	134,092	$245.8	($43.1)	$202.8

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-4. Price Impacts and Benefits to Non-Curtailed Loads, Low Peak (LP) Case

Zone	MADRI	Curtailment Impacts During 152 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$8	5%	126	2.0%	6,184	$7.8	($1.1)	$6.7
DPL	DE/MD**	$10	5.8%	71	2.0%	3,466	$5.1	($0.3)	$4.8
PECO	PA	$11	6.4%	152	2.0%	7,434	$12.6	($3.8)	$8.8
PEPCO	DC/MD**	$9	5.0%	120	2.0%	5,869	$7.9	($2.4)	$5.4
PSEG	NJ	$10	5.8%	191	2.0%	9,200	$13.6	($1.2)	$12.3
AECO	NJ	$7	3.7%	-	-	2,390	$2.6	$0.2	$2.8
JCPL	NJ	$8	5.2%	-	-	5,284	$6.6	($0.5)	$6.1
DUQ	PA	$0	0.3%	-	-	2,620	$0.2	$0.0	$0.2
METED	PA	$8	4.9%	-	-	2,449	$3.1	($0.5)	$2.5
PENELEC	PA	$4	2.8%	-	-	2,517	$1.7	($0.4)	$1.3
PPL	PA	$7	4.6%	-	-	6,566	$7.1	($0.7)	$6.4
APS	PA/MD**	$5	3.1%	-	-	7,848	$5.9	($5.7)	$0.2
RECO	NY	$6	3.8%	-	-	378	$0.3	$0.0	$0.4
AEP	-	$0	0.5%	-	-	20,100	$1.5	($0.8)	$0.7
DAY	-	$0	0.4%	-	-	2,864	$0.2	$0.0	$0.2
DOM	-	$2	1.8%	-	-	15,993	$5.8	($1.4)	$4.3
COMED	-	$1	0.5%	-	-	17,337	$1.5	($0.0)	$1.5
Total in Curtailed Zones		$10	5.6%	660	2.0%	32,152	$47.0	($8.9)	$38.1
Total in Non-Curtailed Zones		$3	1.9%	0	0.0%	86,347	$36.5	($9.9)	$26.6
Total by State	PA	$7	4.3%	152	0.6%	24,936	$27.2	($7.9)	$19.3
	NJ	$9	5.3%	191	1.1%	16,874	$22.8	($1.6)	$21.2
	DE	$10	5.8%	48	2.0%	2,375	$3.5	($0.2)	$3.3
	MD	$8	4.8%	230	1.8%	12,703	$15.8	($4.0)	$11.9
	DC	$9	5.0%	36	2.0%	1,770	$2.4	($0.7)	$1.6
MADRI Total		$8	5.0%	657	1.1%	58,657	$71.7	($14.4)	$57.3
Non-MADRI Total		$1	2.3%	3	0.0%	59,842	$11.8	($4.4)	$7.4
Total PJM		$5	2.9%	660	0.6%	118,500	$83.5	($18.8)	$64.7

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-5. Price Impacts and Benefits to Non-Curtailed Loads, High Fuel (HF) Case

Zone	MADRI	Curtailment Impacts During 135 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual Load (MW)	Gross Benefits (Million $)	ARR Change (Million $)	Net Benefits (Million $)
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	[E]	[F]	[G]	[H]
BGE	MD	$17	7%	151	2.2%	6,583	$15.5	($0.7)	$14.7
DPL	DE/MD**	$32	12.0%	85	2.2%	3,696	$16.2	($3.8)	$12.4
PECO	PA	$21	8.4%	182	2.2%	7,927	$22.8	($3.7)	$19.1
PEPCO	DC/MD**	$21	7.5%	143	2.2%	6,225	$18.0	($4.5)	$13.5
PSEG	NJ	$19	7.7%	227	2.3%	9,819	$25.8	($1.1)	$24.7
AECO	NJ	$16	5.6%	-	-	2,561	$5.7	$0.2	$5.8
JCPL	NJ	$19	7.5%	-	-	5,661	$14.3	($0.7)	$13.6
DUQ	PA	$1	0.9%	-	-	2,777	$0.5	$0.0	$0.5
METED	PA	$19	7.0%	-	-	2,619	$6.7	($0.9)	$5.8
PENELEC	PA	$10	4.1%	-	-	2,682	$3.5	($0.6)	$2.9
PPL	PA	$18	7.1%	-	-	7,008	$16.8	($1.2)	$15.7
APS	PA/MD**	$7	2.9%	-	-	8,332	$7.4	($6.0)	$1.4
RECO	NY	$15	6.7%	-	-	404	$0.8	$0.1	$0.9
AEP	-	$1	0.8%	-	-	21,280	$3.4	($0.9)	$2.5
DAY	-	$1	0.8%	-	-	3,005	$0.5	($0.0)	$0.5
DOM	-	$3	1.6%	-	-	17,051	$7.4	($1.7)	$5.6
COMED	-	$2	1.0%	-	-	18,084	$3.7	($0.0)	$3.6
Total in Curtailed Zones		$21	8.0%	788	2.2%	34,249	$98.2	($13.8)	$84.4
Total in Non-Curtailed Zones		$6	2.5%	0	0.0%	91,466	$70.7	($11.9)	$58.8
Total by State	PA	$15	6.0%	182	0.7%	26,571	$53.6	($9.0)	$44.6
	NJ	$19	7.3%	227	1.2%	18,040	$45.7	($1.6)	$44.0
	DE	$32	12.0%	58	2.2%	2,533	$11.1	($2.6)	$8.5
	MD	$19	6.8%	274	2.0%	13,504	$33.9	($6.0)	$27.9
	DC	$21	7.5%	43	2.2%	1,877	$5.4	($1.3)	$4.1
MADRI Total		$18	7.6%	785	1.2%	62,524	$149.6	($20.6)	$129.1
Non-MADRI Total		$2	3.0%	3	0.0%	63,191	$19.2	($5.1)	$14.1
Total PJM		$10	4.0%	788	0.6%	125,715	$168.9	($25.7)	$143.2

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).

Table A-6. Price Impacts and Benefits to Non-Curtailed Loads, Low Fuel (LF) Case

Zone	MADRI	Curtailment Impacts During 152 Hours w/ At Least One Zone Curtailing							
		Weighted Average LMP Reduction		Average Load Curtailment		Average Residual	Gross Benefits	ARR Change	Net Benefits
		($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	Load (MW) [E]	(Million $) [F]	(Million $) [G]	(Million $) [H]
BGE	MD	$12	6%	134	2.0%	6,552	$11.5	($0.8)	$10.6
DPL	DE/MD**	$23	12.4%	75	2.0%	3,678	$13.1	($3.6)	$9.4
PECO	PA	$14	8.0%	160	2.0%	7,859	$17.0	($4.1)	$13.0
PEPCO	DC/MD**	$15	7.2%	127	2.0%	6,214	$14.3	($3.9)	$10.4
PSEG	NJ	$13	7.2%	201	2.0%	9,724	$18.9	($1.3)	$17.6
AECO	NJ	$11	5.2%	-	-	2,531	$4.1	$0.0	$4.1
JCPL	NJ	$12	6.8%	-	-	5,580	$9.9	($0.6)	$9.4
DUQ	PA	$1	0.7%	-	-	2,752	$0.3	($0.0)	$0.3
METED	PA	$11	5.9%	-	-	2,593	$4.4	($0.6)	$3.8
PENELEC	PA	$5	2.9%	-	-	2,662	$1.9	($0.3)	$1.6
PPL	PA	$10	5.7%	-	-	6,944	$10.3	($0.8)	$9.5
APS	PA/MD**	$4	2.6%	-	-	8,309	$5.4	($4.9)	$0.5
RECO	NY	$8	5.3%	-	-	399	$0.5	$0.1	$0.6
AEP	-	$1	0.5%	-	-	21,352	$1.8	($0.8)	$1.1
DAY	-	$1	0.5%	-	-	3,041	$0.2	($0.0)	$0.2
DOM	-	$2	1.5%	-	-	17,014	$5.1	($1.3)	$3.9
COMED	-	$1	0.7%	-	-	18,475	$2.0	($0.0)	$2.0
Total in Curtailed Zones		$14	7.8%	699	2.0%	34,028	$74.8	($13.8)	$61.0
Total in Non-Curtailed Zones		$3	2.1%	0	0.0%	91,649	$46.1	($9.2)	$36.9
Total by State	PA	$9	5.2%	160	0.6%	26,357	$36.3	($7.9)	$28.4
	NJ	$12	6.8%	201	1.1%	17,835	$33.0	($1.9)	$31.1
	DE	$23	12.4%	52	2.0%	2,520	$9.0	($2.5)	$6.5
	MD	$13	6.6%	244	1.8%	13,456	$26.1	($5.5)	$20.6
	DC	$15	7.2%	38	2.0%	1,874	$4.3	($1.2)	$3.1
MADRI Total		$12	7.3%	696	1.1%	62,042	$108.6	($19.0)	$89.6
Non-MADRI Total		$1	2.6%	3	0.0%	63,635	$12.3	($4.1)	$8.3
Total PJM		$6	3.6%	699	0.6%	125,677	$120.9	($23.0)	$97.9

Notes:
[A] and [B]: LMP reduction is weighted by hourly residual load.
[F] = [A] x [E] x number of hours with at least one zone curtailed.
[G]: 97% of ARRs are allocated to non-curtailed loads; the remainder is allocated to curtailed loads.
[H] = [F] + [G].
Benefits in zones spanning multiple states were allocated according to retail sales in June-September, 2005, from EIA form 826 reported in Global Energy Decisions Inc's *Energy Velocity*. Delmarva is allocated 28% to MD and 69% to DE (and 4% to VA). PEPCO is allocated 70% to MD and 30% to DC. APS, which has spillover price effects, is allocated 43% to PA and 19% to MD (and 29% to WV, 6% to VA, and 4% to OH).