The Brattle Group

Quantifying Demand Response Benefits in PJM

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Study Team

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Substantial support and contributions by PJM, esp. Joe Kerecman, John Wilhelm, Serhan Ogur, Howard Haas, and Jeff Bastian.

Comments and sponsorship by MADRI Executive Committee.

Agenda

- Executive Summary
- Methodology and Findings
- Other Benefits
- Offsets Not Considered
- Suggested Future Research

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- **Executive Summary**
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Study Objectives

Estimate the value of mitigating peak market prices through demand curtailment.

As specified in the RFP:

- **Using a simulation model, quantify customers' LMP savings (net of FTR revenues) from curtailing demand by 3% in the top twenty 5-hr LMP blocks that occurred within BGE, Delmarva, PECO, PEPCO and PSEG during 2005.**
- **Perform analyses under actual market conditions and under a range of alternative loads and fuel prices: weather normalized, high peak, low peak, high fuel, and low fuel.**

Study Scope

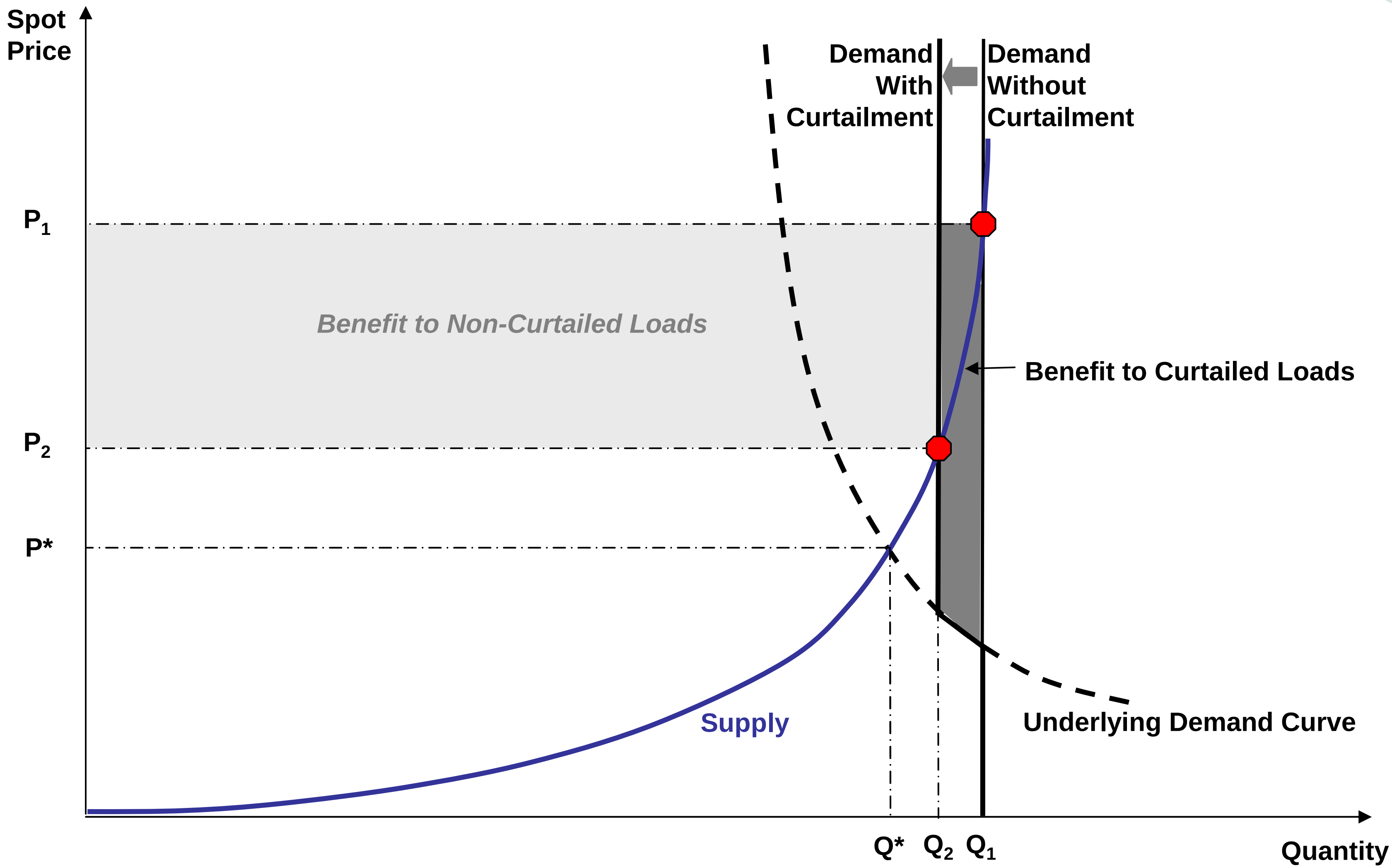
What We Quantified

- Primary focus: energy market impacts and benefits to non-curtailed loads
- Additional rough estimates: energy and capacity benefits to curtailed loads

What We Did NOT Quantify

- Other benefits: competitiveness, price stability, insurance, real-time response, capacity market impacts, T&D savings.
- Secondary market effects that could significantly offset benefits to non-curtailed loads
- Environmental implications

Conceptual Framework for Energy Benefits



Summary of Findings

	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.

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  - Benefits to Non-Curtailed Loads
  - Benefits to Curtailed Loads
- **Other Benefits**
- **Offsets Not Considered**
- **Suggested Future Research**

Overview of Methodology for Estimating Benefits to Non-Curtailed Loads

1. **Calibrate and Validate "Dayzer" Model**
2. **Construct Alternative Reference Cases**
3. **Develop Curtailment Cases**
4. **Estimate Price Impacts and Benefits to Non-Curtailed Loads**

Introduction to the Dayzer Model

DAYZER

Day-Ahead Market Analyzer

DAYZER is a user-friendly detailed market analysis tool which facilitates the understanding of the complex operation of electricity markets with little training and effort.

Key Features

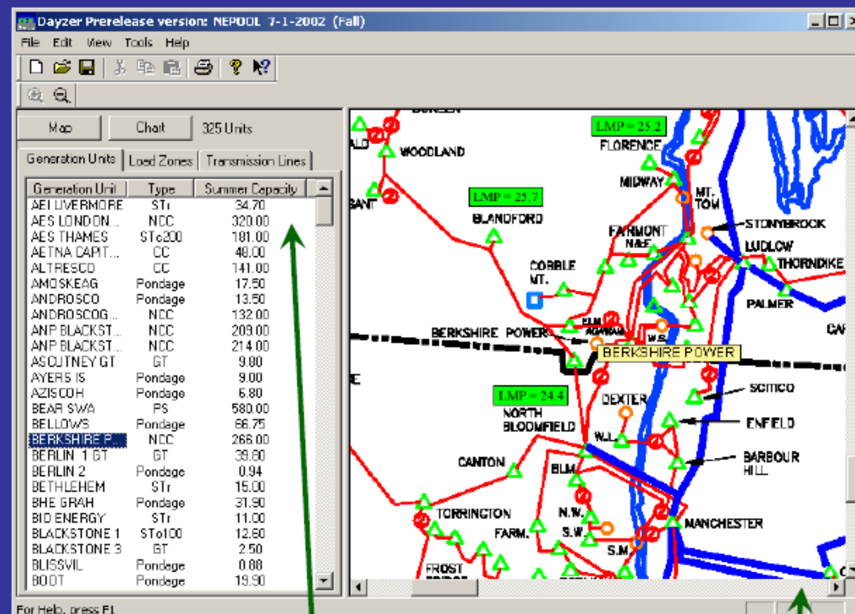
Open Architecture
Powerful Algorithms
Intuitive Data Visualization

Who should use DAYZER?

Analysts: DAYZER is a powerful tool that can forecast Day-Ahead hourly LMPs (Zonal or Nodal), Shadow Prices and Congestion Costs under "what if" scenarios.

Market Monitors: DAYZER is useful tool that can be used to analyze bidding behavior and different market equilibria (marginal costs, Nash, etc...)

www.CES-US.com



System, Unit, Line, and Load Zone characteristics shown in tabular format.

Mini-GIS Engine showing system components and LMPs

Cambridge Energy Solutions
A Provider of Information and Energy Solutions

Source: www.ces-us.com

Refinements to Input Data

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.
	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.
	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 and NYMEX spot prices (data for all fuels provided by CES).
	Emission Allowance Prices	Daily spot prices from Cantor Fitzgerald (data provided by CES).
	Generator Outages	Confidential unit outage schedules from PJM.
	Imports/Exports from Outside PJM	Actual day-ahead scheduled hourly interchanges at each interface point (data provided by CES).
	Unit Bids	Calibrated unit bids to publicly available bid data, by region and by technology type.

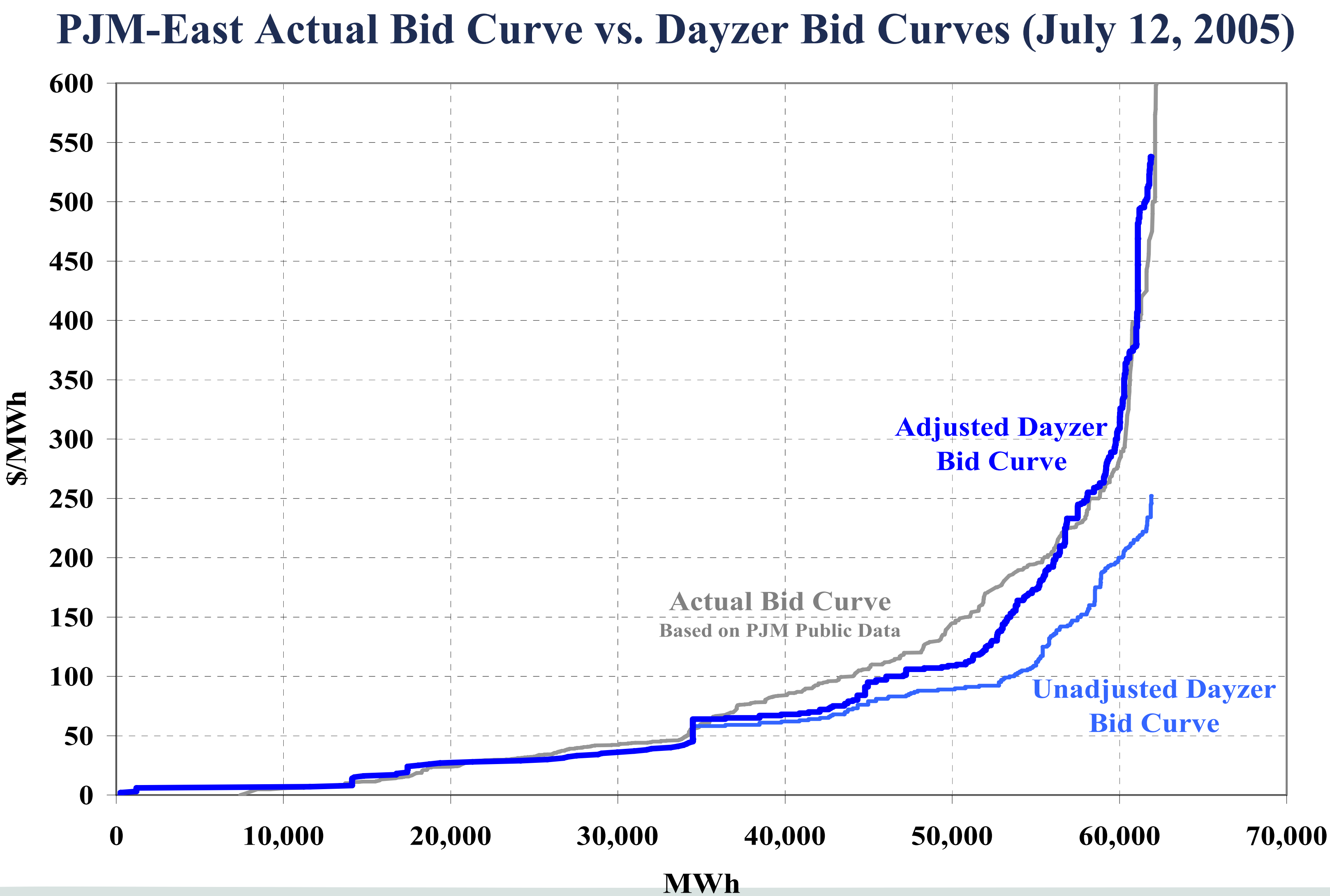
"CES" refers to Cambridge Energy Solutions, the provider of the Dayzer software, CES propriety data, and daily downloads of data from the PJM website.

Refinements to Input Data (cont.)

Category of Inputs		Sources and Refinements
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).

"CES" refers to Cambridge Energy Solutions, the provider of the Dayzer software, CES propriety data, and daily downloads of data from the PJM website.

Calibration of Bids



Calibration and Validation of Model

Simulated LMPs Closely Replicate Actual DA LMPs

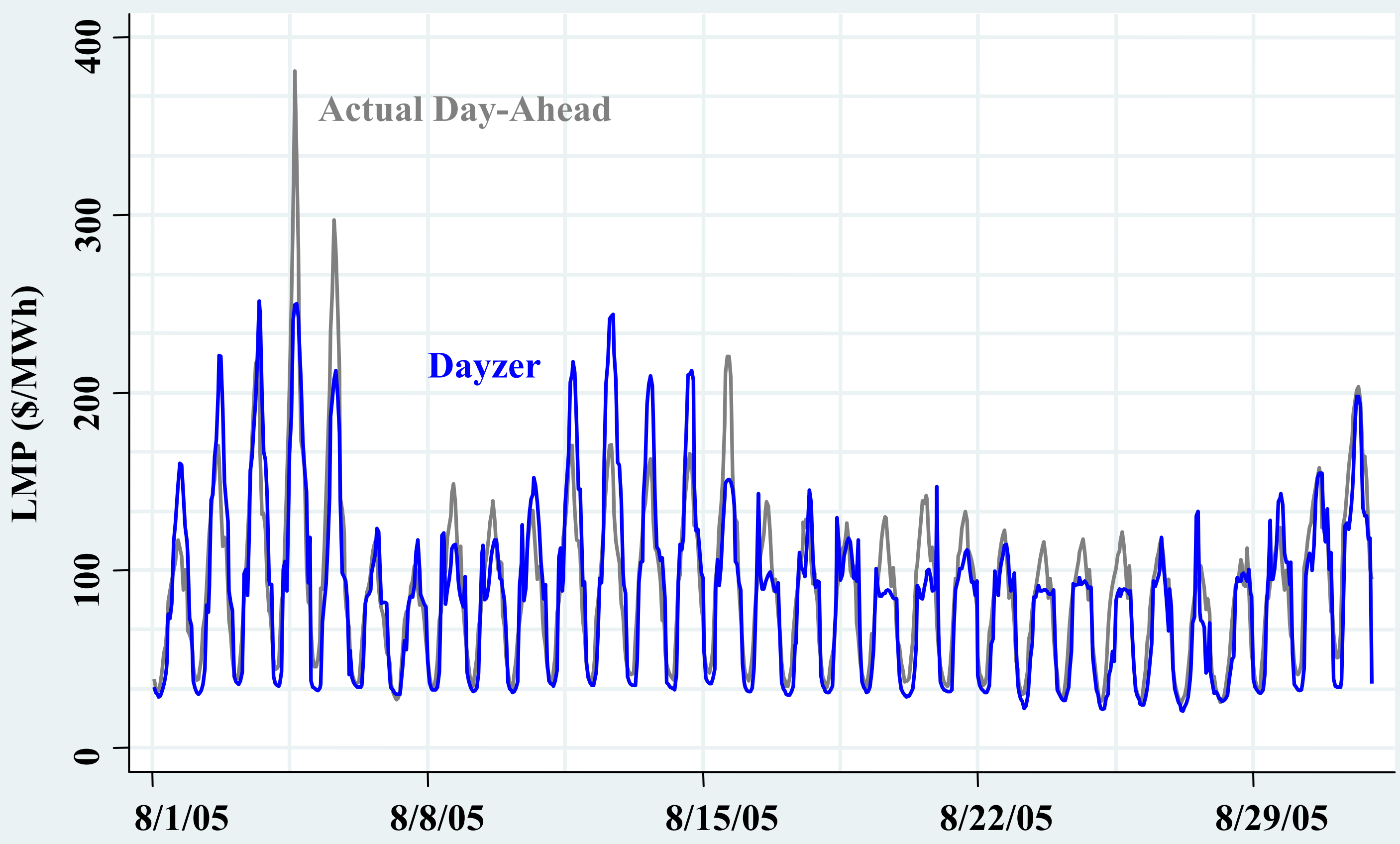
Region	Zone Name	Actual		Dayzer		Dayzer Minus Actual	
		Top 100 Hours	Jun-Sep Avg Peak	Top 100 Hours	Jun-Sep Avg Peak	Top 100 Hours	Jun-Sep Avg Peak
South	DOM	$181	$100	$151	$91	($31)	($9)
East	PEPCO	$212	$110	$207	$99	($6)	($11)
East	BGE	$200	$106	$191	$99	($8)	($7)
East	DPL	$193	$104	$200	$99	$7	($5)
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)

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

Calibration and Validation of Model

Simulated LMPs Closely Replicate Actual DA LMPs (cont.)

Hourly Eastern Hub LMP Comparison (August 2005)

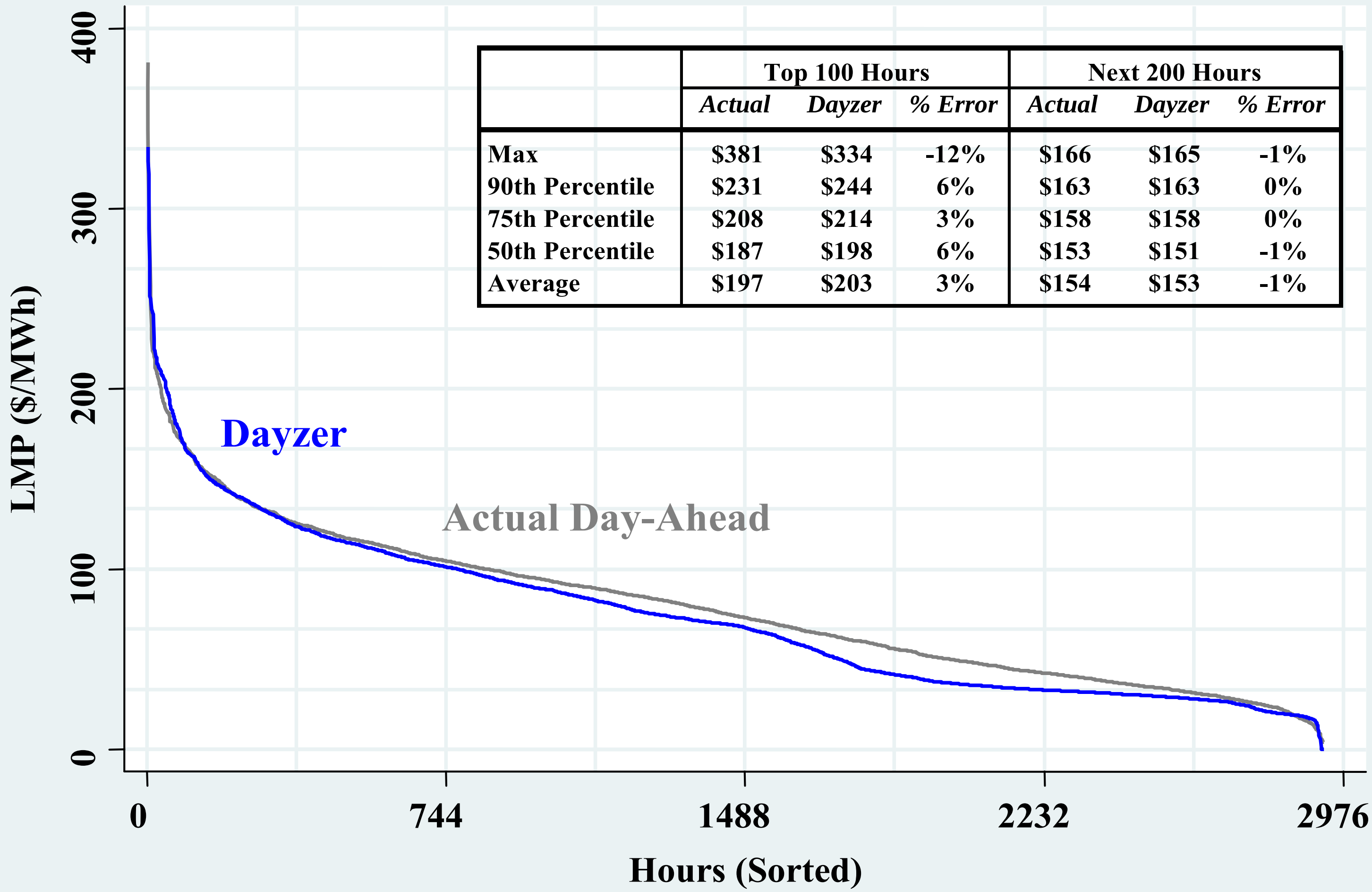


Actual day-ahead LMPs from Global Energy Decision Inc.'s *Velocity Suite*, August 2006 data release.

Calibration and Validation of Model

Simulated LMPs Closely Replicate Actual DA LMPs (cont.)

Hourly Eastern Hub LMPs (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%

Actual day-ahead LMPs from Global Energy Decision Inc.'s *Velocity Suite*, August 2006 data release.

Construction of Alternative Reference Cases

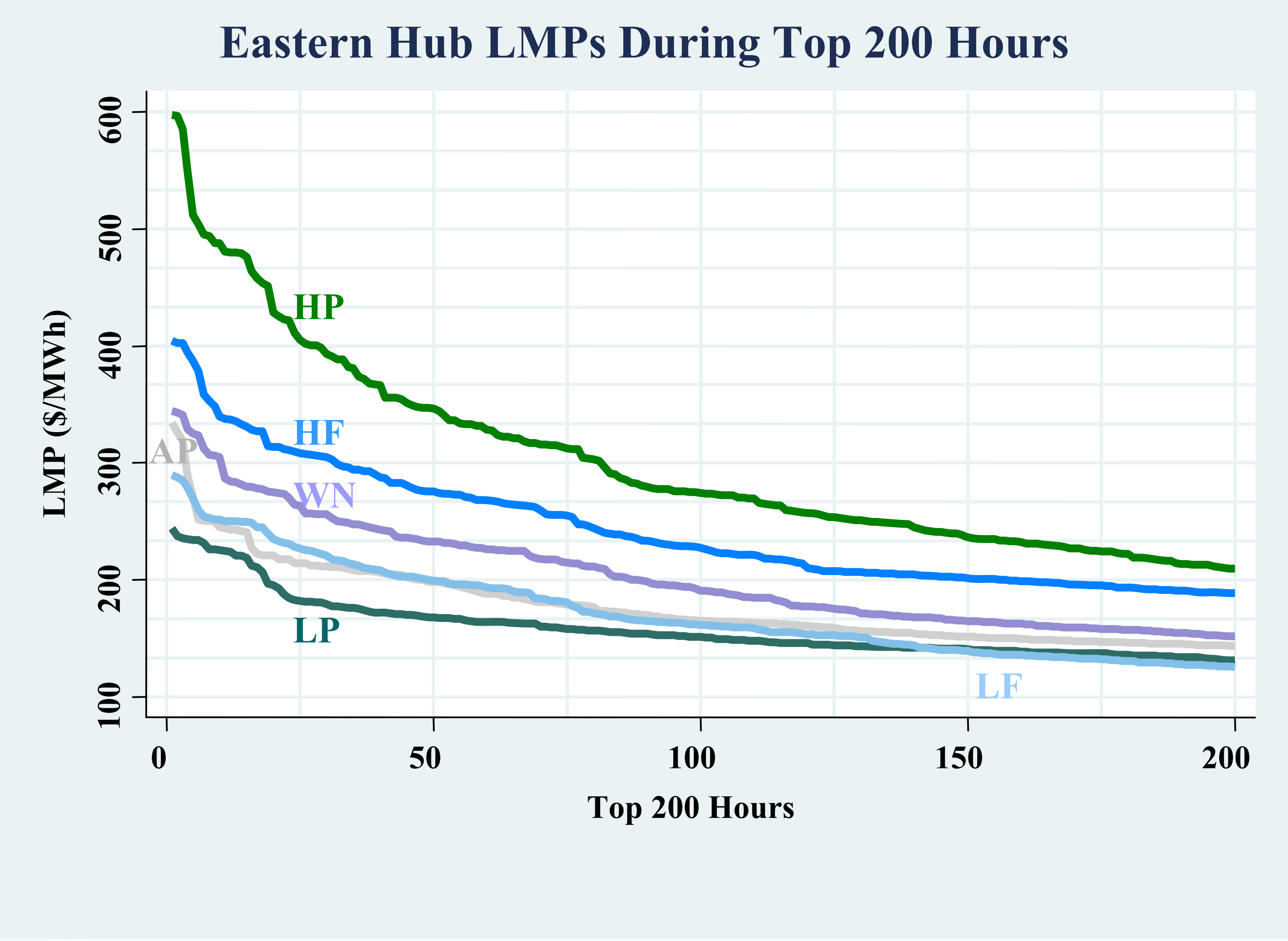
Normalized Case (N): normalize load, fuel prices, and emission allowance prices.

High Peak (HP) and Low Peak (LP) Cases: ±6% of normalized load; normalized fuel and emission allowance prices.

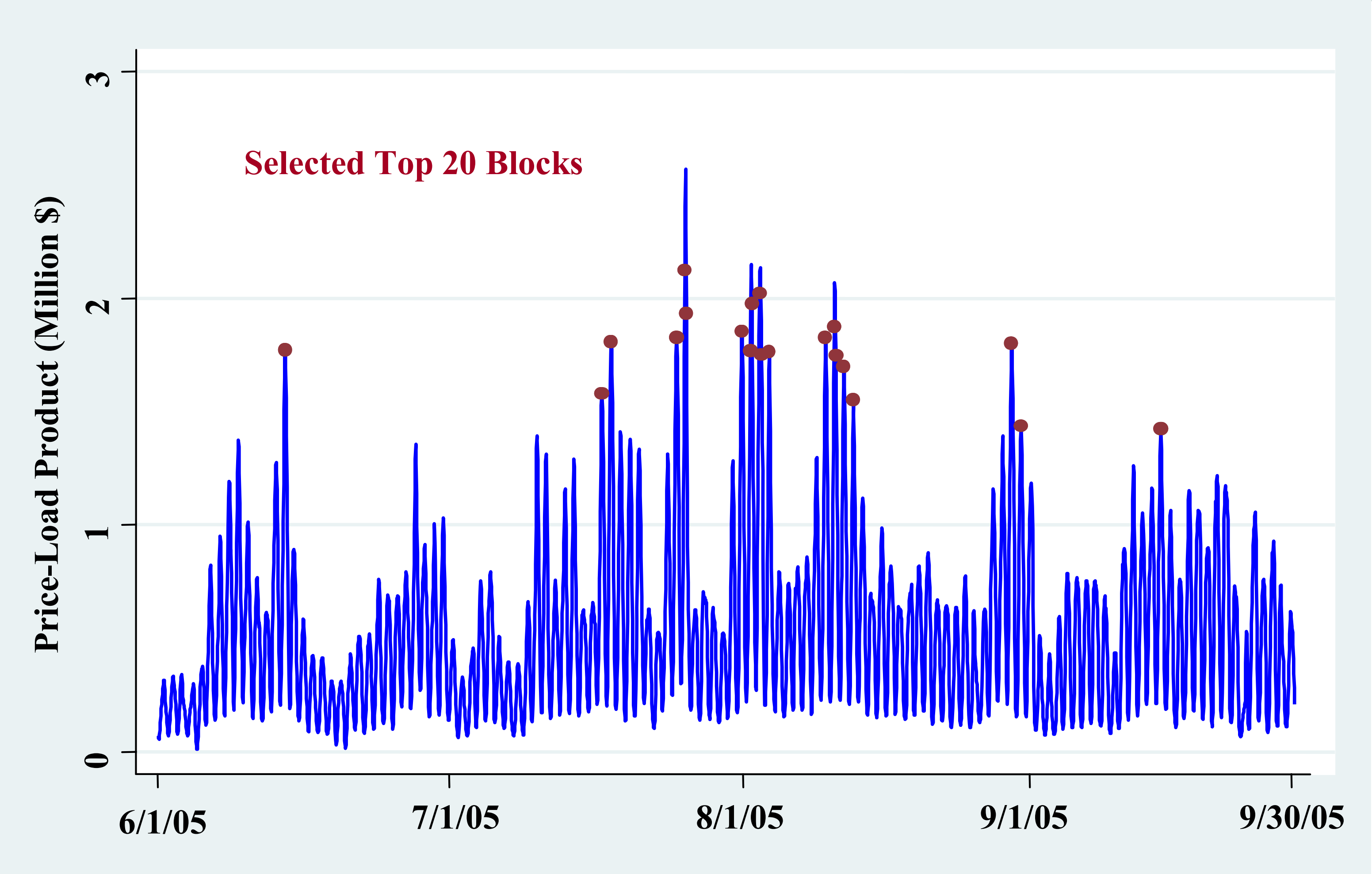
High Fuel (HF) and Low Fuel (LF) Cases: based on 2007 forward prices, with high and low based on historical distributions of spot relative to forward; normalized emission allowance prices; weather-normalized load.

Construction of Alternative Reference Cases

Reference Cases Capture a Range of Market Conditions



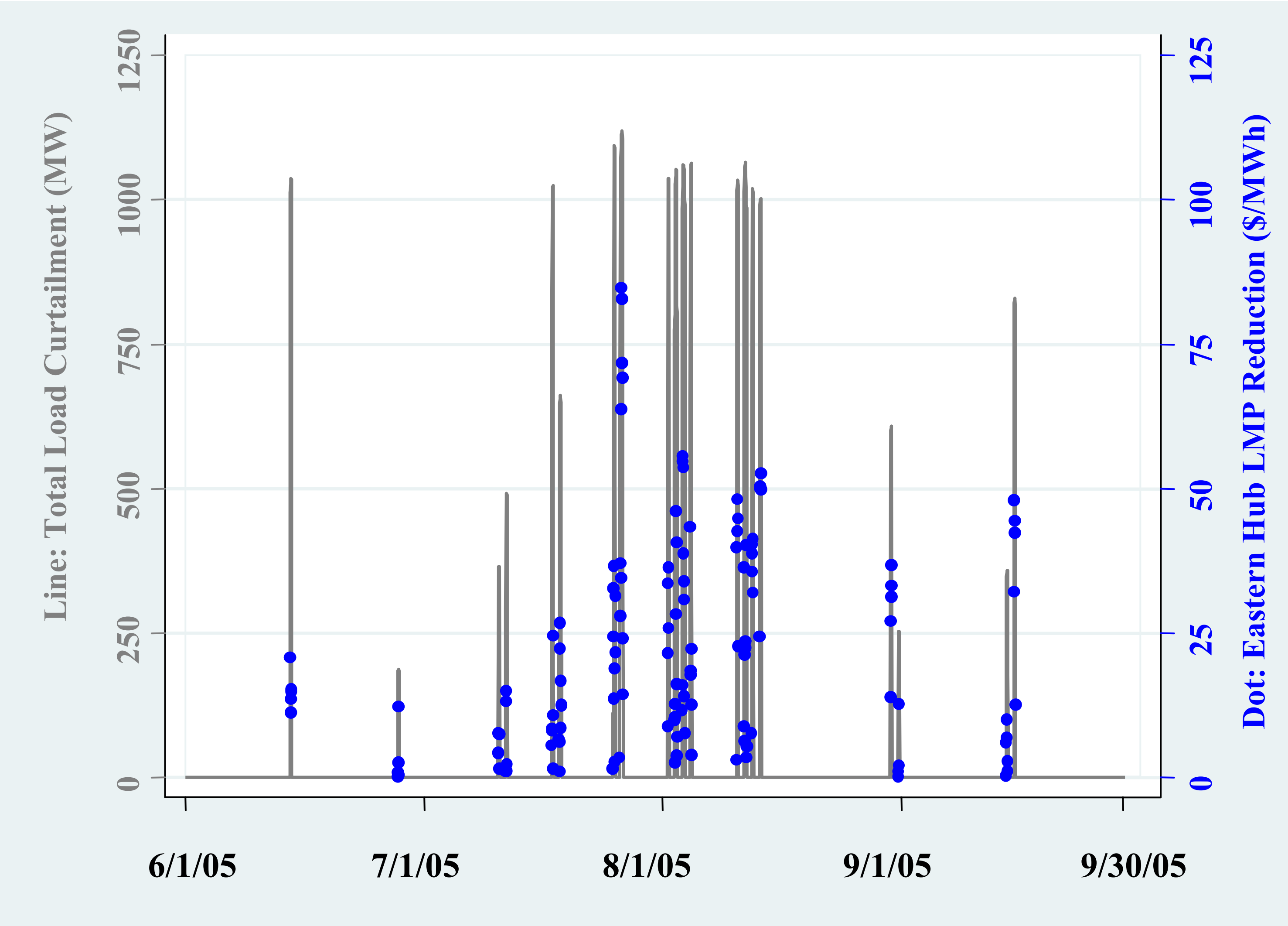
Identification of Top Twenty 5-hour Blocks in PSEG



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.

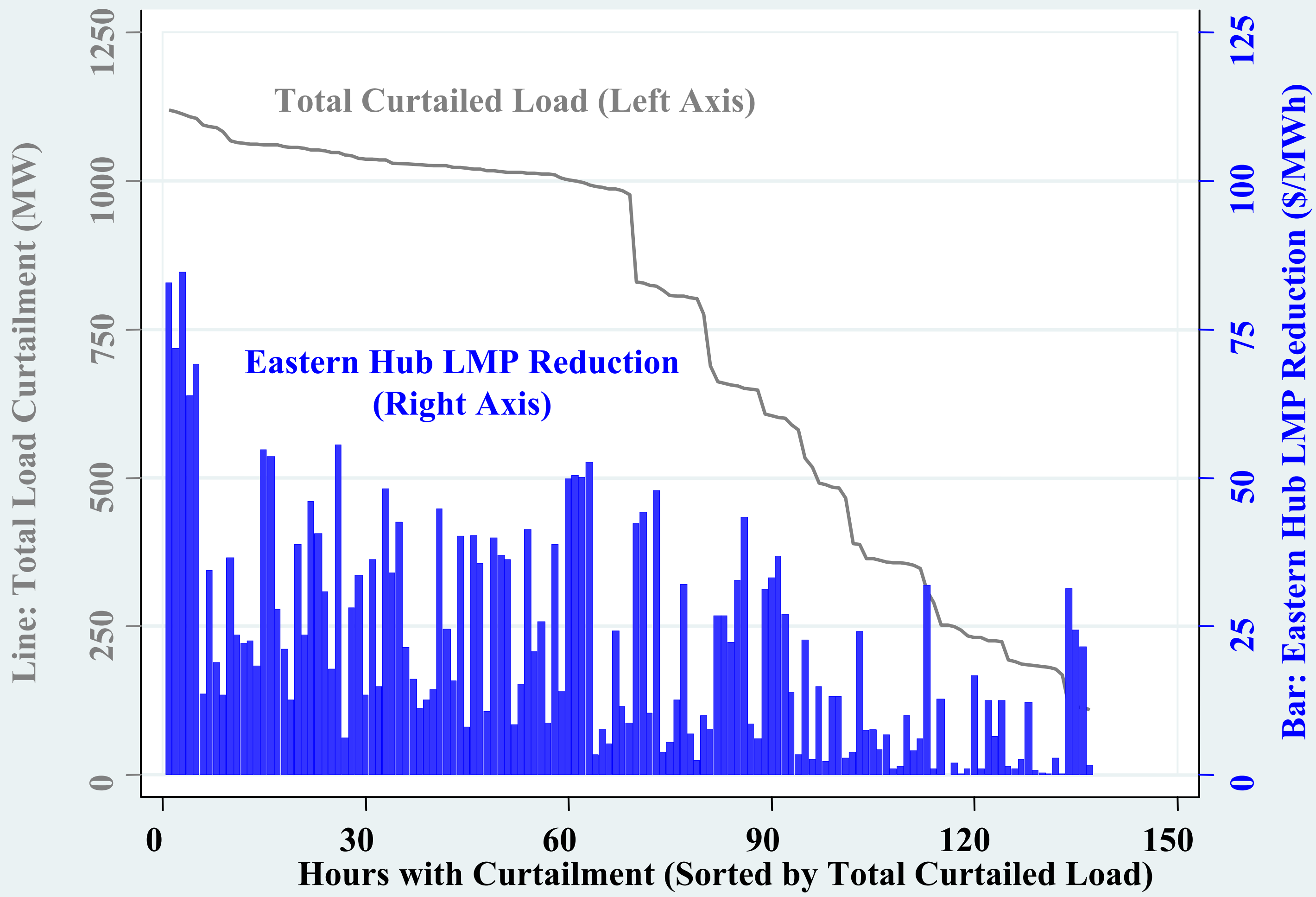
Development of Curtailment Cases

Price Impact of Load Curtailment (AP Case)



Development of Curtailment Cases

Price Impact of Load Curtailment (AP Case)



Benefits to Non-Curtailed Loads

Gross Savings = Reduction in Zonal LMP * Residual Zonal Load

Net Savings = Gross Savings – Change in Customer ARR Value

- PJM provided ARR allocations
- *Brattle* wrote program to value ARR portfolios with and without demand curtailment

Report gross and net customer savings for each MADRI state

- For multi-state zones, allocate savings according to shares of retail sales

Benefits to Non-Curtailed Loads

	Weighted Average LMP Reduction		Average Load Curtailment		Average Residual Load (MW)	Gross Direct Benefits (Million $)	ARR Change (Million $)	Net Direct Benefits (Million $)
	($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	[E]	[F]	[G]	[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	**$12**	**6.7%**	**211**	**1.2%**	**17,640**	**$30.1**	**($1.5)**	**$28.6**
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%**	**60,313**	**$98.0**	**($14.6)**	**$83.4**
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%**	**18,356**	**$36.5**	**($1.5)**	**$35.0**
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%**	**62,705**	**$123.0**	**($20.5)**	**$102.5**

[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 *Velocity Suite*. 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).

Benefits to Non-Curtailed Loads (cont.)

	Weighted Average LMP Reduction		Average Load Curtailment		Average Residual Load (MW)	Gross Direct Benefits (Million $)	ARR Change (Million $)	Net Direct Benefits (Million $)
	($/MWh) [A]	(%) [B]	(MW) [C]	(%) [D]	[E]	[F]	[G]	[H]
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**	**1.2%**	**19,581**	**$67.9**	**($2.2)**	**$65.6**
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**	**1.2%**	**66,668**	**$217.5**	**($33.9)**	**$183.6**
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%**	**17,252**	**$23.1**	**($1.5)**	**$21.6**
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%**	**59,036**	**$72.0**	**($14.3)**	**$57.6**

[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.
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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 *Velocity Suite*. 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).

Benefits to Non-Curtailed Loads (cont.)

	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 Direct Benefits (Million $) [F]	ARR Change (Million $) [G]	Net Direct Benefits (Million $) [H]
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%**	**18,444**	**$46.5**	**($1.6)**	**$44.9**
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%**	**62,929**	**$150.5**	**($20.5)**	**$129.9**
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%**	**18,233**	**$33.5**	**($1.8)**	**$31.6**
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	**$11**	**7.3%**	**696**	**1.1%**	**62,441**	**$109.1**	**($18.9)**	**$90.2**

[A] and [B]: LMP reduction is weighted by hourly residual load.
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Benefits Are Smaller When Only One Zone Is Curtailed

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 Benefit (Million $)	ARR Change (Million $)	Net Benefit (Million $)	Net Benefit (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**

[A]: LMP reduction is weighted by hourly residual load.
[E] = [A] x [D] x 100 (number of hours with at least one zone curtailed).
[G] = [E] + [F].

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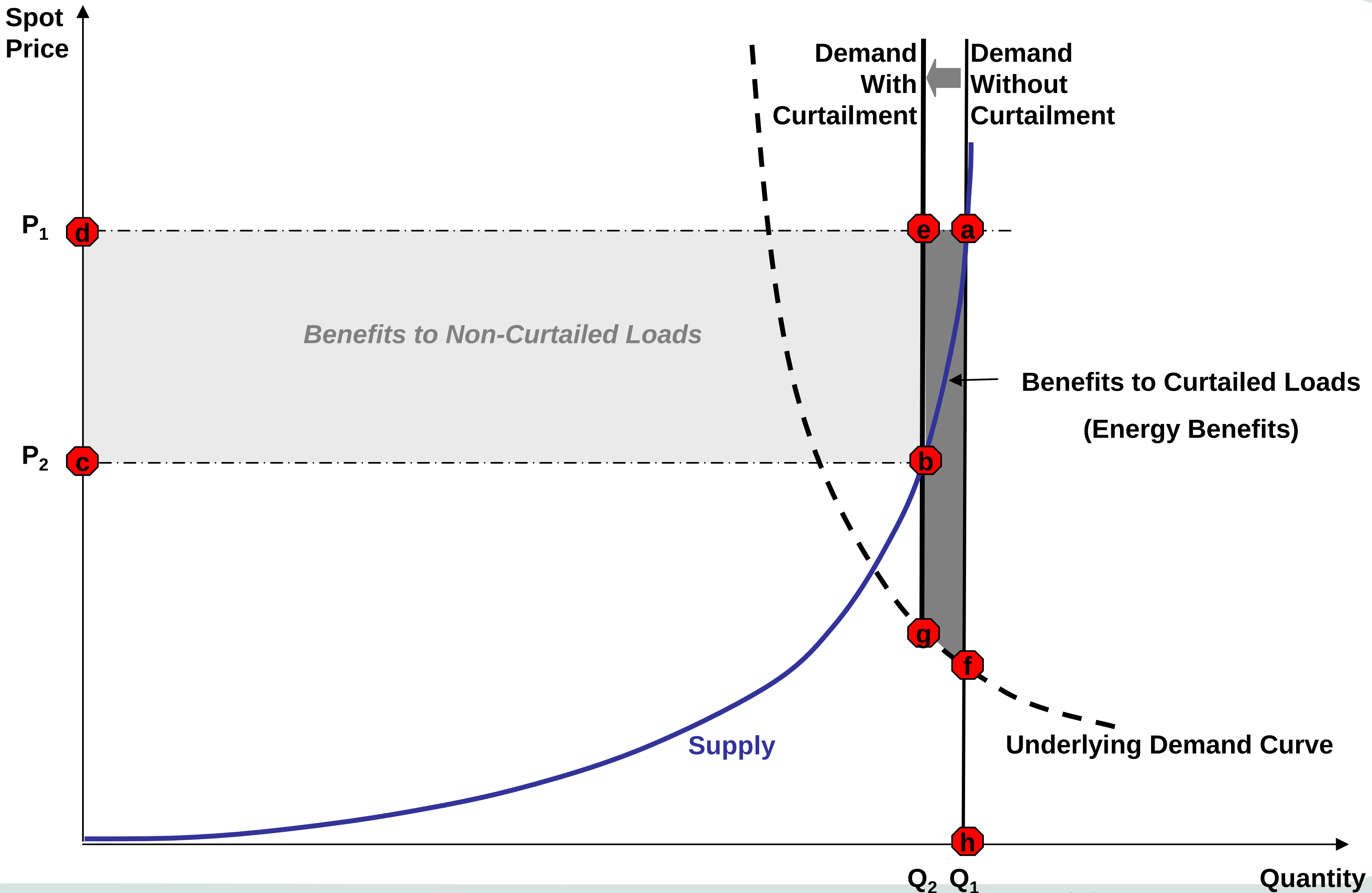
Benefits to Curtailed Loads

Conceptual Framework



Energy Benefits to Curtailed Loads

	Average Curtailed Load (MW) [A]	Benefits to Curtailed Loads ($/MWh)			Benefits to Curtailed Loads (Million $)		
		Lower Bound [B]	Intermediate Estimate [C]	Upper Bound [D]	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**

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

Energy Benefits to Curtailed Loads (cont.)

	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]
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**

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

Energy Benefits to Curtailed Loads (cont.)

	Average Curtailed Load (MW) [A]	Benefits to Curtailed Loads ($/MWh)			Benefits to Curtailed Loads (Million $)		
		Lower Bound [B]	Intermediate Estimate [C]	Upper Bound [D]	Lower Bound [E]	Intermediate Estimate [F]	Upper Bound [G]
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**

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

Capacity Benefits to Curtailed Loads

Capacity Benefits = Reduction in Normalized Peak Load (MW)
x 1.15 Reserve Margin
x Long-Run Marginal Cost of Capacity ($/kW-Yr)

= 1100 MW x 1.15 x $58/kW-Yr

= **$73 Million**

Agenda

- Executive Summary
- Methodology and Findings
- **Other Benefits**
  - Enhanced Market Competition
  - Reduced Price Volatility
  - Insurance Against Extreme Events
  - Real-Time vs. Day-Ahead Curtailments
  - Capacity Market Impacts
  - Avoided/Deferred T&D Costs
- Offsets Not Considered
- Suggested Future Research

Enhanced Market Competition

Expanding demand response programs, including curtailment programs, would increase the elasticity of demand and thereby increase the competitiveness of the market.

Simple game-theoretical models suggest that doubling the elasticity of demand would enhance competitiveness as much as reducing market concentration by 50%.

Enhanced competitiveness could result in lower energy prices and lower capacity prices both in the short term and the long term.

Reduced Price Volatility and Rate Variance

Most end-use customers are risk-averse.

There is value to reducing the price variance, not just reducing expected prices, faced by customers.

Insurance Against Extreme Events

There are many possible events that 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 wave 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.

Capacity Market Impacts

Demand response could reduce capacity prices by reducing peak loads and therefore reducing the demand for capacity.

With reduced demand, the capacity market could clear at a lower price, more so in the short-run than the long-run.

Real-Time vs. Day-Ahead Curtailments

DR is likely to be more valuable in RT vs. DA.

In the long-term, RT and DA prices should converge, perhaps subject to a risk premium.

But RT markets tend to be more volatile and have higher price spikes than DA.

Hence, load curtailment can have the greatest price impact if "dispatchable" in real-time, mitigating unexpectedly tight market conditions.

As modeled, benefits may underestimate the benefit of DR.

Avoided/Deferred T&D Costs

DR may help to avoid or defer transmission and distribution (T&D).

These benefits, if they do occur, are likely to be larger for distribution than transmission.

The magnitude of these benefits depend on the location of the DR.

Distribution benefits may or may not occur in areas with high DA or RT energy prices.

Agenda

- Executive Summary
- Methodology and Findings
- Other Benefits
- **Offsets Not Considered**
    - Load Shifting and Demand Elasticity
    - Long-Term Equilibrium: Accelerated Retirements, Delayed Construction, Capacity Price Increases
    - Costs of DR Programs
- Suggested Future Research

Shifting of Load

Shifting of curtailed load to other hours mitigates some of the calculated benefits of DR.

Some DR will <u>no</u>t result in load shifting.

Some DR will result in load shifting, e.g., reduction in air conditioning.

Some of this load shifting may occur to hours in the 5-hour curtailment block; other load shifting may be outside the curtailment block.

Load shifting effects may likely be small compared to the as modeled reduction benefits, although the amount depends on the details of the DR measure.

Offsets not Considered

Existing Demand Elasticity

The 3% curtailment is a net number, not a gross number.

More than 3% of new DR is needed to obtain a net reduction of 3% because price reductions resulting from demand curtailment could dampen the extent to which other customers on real-time prices respond to high market 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.

- Assuming a short-term demand price elasticity of -0.1, a 10% reduction in price will reduce the responsiveness of loads on real-time prices, increasing their loads by 1% and mitigating some (but not all) of the price reduction due to new DR.
- In the long-term, demand is more price responsive, resulting in less of a sustained price reduction than in the short-term.

Capacity Shifts in Long-term Equilibrium

If DR reduces recovery of fixed costs necessary for an existing generation unit to stay in the market, then that unit could retire; construction of new capacity could be delayed.

This reduction in installed capacity would increase electricity prices, although this increase will likely be less than the short-term reduction in prices due to DR.

In addition, in a competitive market equilibrium, reduced energy prices would likely be offset by higher capacity prices, as suppliers raise their capacity bids to recover their going-forward fixed costs.

This study has not analyzed where and when 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 resulting 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.

Costs of DR Policies

DR policies have a cost, and these costs must be considered in order to have cost-effective DR.

The costs of achieving a 3% reduction in demand during the top twenty five-hour price blocks is not considered.

These costs may likely depend on the size and frequency of the curtailments.

The size and frequency of curtailments are likely to depend significantly on DA and RT energy prices and summer weather conditions.

Building GTs can achieve comparable market effects (although their environmental impacts are different).

Environmental Effects not Considered

Environmental effects are probably small and not necessarily beneficial

3% reduction in demand in 1% of the hours reduces total megawatt-hours by 0.03%, assuming no shift in demand.

Some major emissions are capped or soon to be capped.

Similarly, some units' emissions are limited by maximum-run-hour constraints or by emissions limits imposed by their environmental permits.

If curtailed load runs behind-the-meter generation to effectuate its load reduction, then the environmental effects may be negative.

However, demand reductions during periods of peak load might achieve modest environmental benefits by reducing generation of the dirtiest plants in load centers on the hottest, smoggiest days.

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- Executive Summary
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Suggested Future Research

Estimate Other Benefits, especially

- Competitiveness
- Capacity market benefits
- Real-time vs. day-ahead

Analyze Offsetting Factors, especially

- Load shifts
- Long-term equilibrium effects
- Costs of DR programs

Build on Present Study to Analyze Program Design

- Assess costs, participation, effectiveness of alternative DR program designs in other markets
- Use Dayzer to simulate the market under various types of programs.

Additional Reading

- Ahmad Faruqui, “Using dynamic pricing to strengthen your AMI business cases” presented to the MADRI Executive Committee, *The Brattle Group,* January 12, 2007.
- Ahmad Faruqui, "Cost-Benefit Analysis of Smart Metering," presented at NARUC Annual Convention, Miami Beach, Florida, *The Brattle Group*, November 14, 2006.
- Ahmad Faruqui, "Pricing Programs: Time-of-Use and Real Time," in *Encyclopedia of Energy Engineering*, 2007, forthcoming.
- Ahmad Faruqui, “2050: A pricing odyssey,” *The Electricity Journal*, October 2006.
- Robert Earle and Ahmad Faruqui, “Toward a new paradigm for valuing demand response,” *The Electricity Journal*, May 2006.
- Ahmad Faruqui and Stephen S. George, “Pushing the envelope on rate design,” *The Electricity Journal*, March 2006.
- Ahmad Faruqui and Stephen S. George, “Quantifying customer response to dynamic pricing,” *The Electricity Journal*, May 2005.