Quantifying Demand Response Benefits In PJM

Prepared by

The Brattle Group
44 Brattle Street
Cambridge, MA 02138

Prepared for

PJM Interconnection, LLC and the

Mid-Atlantic Distributed Resources Initiative (MADRI)

January 29, 2007

TABLE OF CONTENTS

1.0 Executive Summary 2

2.0 Study Scope and Organization of this report 5

3.0 Energy Market Impacts and Resulting Benefits to Non-Curtailed Loads 6

3.1. Overview of Methodology 6
3.2. Refinement of Input Data; Calibration and Validation of the Model 7
3.2.1. Refinements to Input Data 7
3.2.2. Calibration of Bids 8
3.2.3. Model Calibration and Validation 10
3.3. Development of Reference Cases 12
3.3.1. The Normalized (N) Case 12
3.3.2. The High Peak (HP) and Low Peak (LP) Cases 13
3.3.3. The High Fuel (HF) and Low Fuel (LF) Cases 14
3.3.4. Simulation of Reference Cases 14
3.4. Development of Curtailment Cases 15
3.4.1. Identification of Top Twenty 5-Hour Blocks 15
3.4.2. Simulation of Curtailment Cases 16
3.5. Estimation of Benefits to Non-Curtailed Loads 16
3.5.1. Direct Energy Price Impact 16
3.5.2. Gross Benefits to Non-Curtailed Loads 19
3.5.3. Net Benefits to Non-Curtailed Loads 20

4.0 Benefits to Curtailed Loads 21

4.1. Energy Benefits 21
4.2. Capacity Benefits 25

5.0 Factors Not Quantified in this Study 26

5.1. Benefits not Quantified 26
5.2. Offsetting Market Effects Not Quantified 28
5.3. Environmental Implications 30

6.0 Conclusions 32

About the Authors 33

Appendix

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.

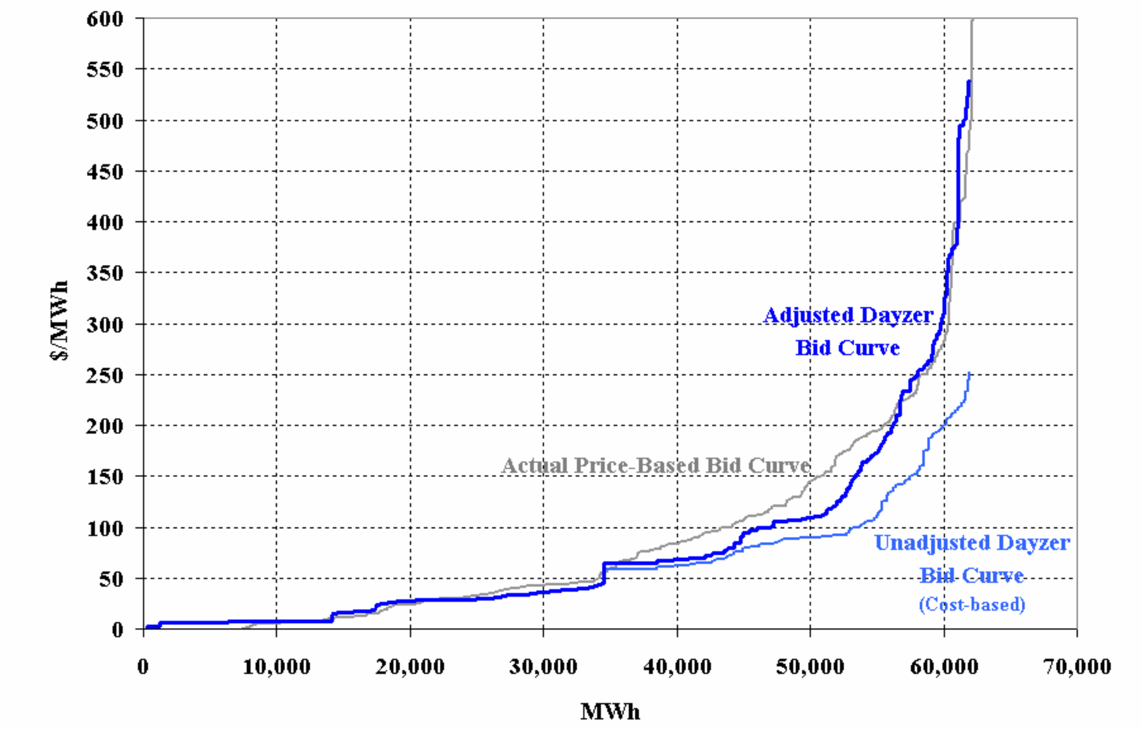
Figure 1 compares the initial cost-based bid curve for PJM-East to the adjusted bid curve and the actual price-based bid curve for one day, July 12, 2005. Similar adjustments were made for the other regions.

[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.