An Economic Welfare Analysis of Demand Response in the PJM Electricity Market

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Abstract

We analyze the economic properties of the economic demand response program in the PJM electricity market in the United States using demand response market data. PJM's program provided subsidies to customers who reduced load in response to price signals. The program incorporated a "trigger point", at a locational marginal price of $75/MWh, at or beyond which payments for load reduction included a subsidy payment. Particularly during peak hours, such a program saves money for the system, but the subsidies involved introduce distortions into the market. We simulate demand-side bidding into the PJM market, and compare the social welfare gains with the subsidies paid to price-responsive load using load and price data for year 2006. The largest economic effect is wealth transfers from generators to non price-responsive loads. Based on the incentive payment structure that was in effect through the end of 2007, we estimate that the social welfare gains exceed the distortions introduced by the subsidies. Lowering the trigger point increases the transfer from generators to consumers, but may result in the subsidy outweighing the social welfare gains due to load curtailment. We estimate that the socially optimal range for the incentive trigger point would be $66/MWh - $77/MWh.

1. Introduction

When electric demand is at or near its peak level, very high cost generating units must be utilized to meet the peak demand. Electricity prices in wholesale markets can increase from less than $50 per MWh off peak to hundreds of dollars per MWh at the peak hour.

In a competitive electricity market where all generators are paid the market clearing price under a uniform price auction structure, even a small reduction in demand can result in an appreciable reduction in system marginal costs of production (Blumsack et al. 2006). These peak price events, although short in duration, add to the average cost per kWh to the consumer. The introduction of demand response (DR) into constrained electricity networks can significantly lower peak energy costs and can potentially act as a check against the exercise of market power by generators (Talukdar, 2002; Rassenti et al., 2002; US-GAO, 2004; Violette et al., 2006a, 2006b; Brattle, 2007). Demand response also has the potential to increase the long-run efficiency of the energy market (Borenstein, 2005).

Based on a review of current utility programs, EPRI estimated that DR has the potential to reduce peak demand in the U.S. by 45,000 MW, roughly 5% (EPRI, 2002). The Brattle Group estimated that even simple real-time pricing could provide annual benefits related to demand response in the tens of millions of dollars, with further potential impacts on capacity and investment needs (Brattle, 2007). DR participation can be increased by providing better price signals, technology, and information, and then letting market participants respond to these price signals (Ruff, 2002). Studies have also identified the need for advanced metering infrastructure (AMI) and building automation controls for enabling the potential of DR and energy efficiency (Lavy, et al., 2002).

In regulated vertically integrated markets, DR is considered as part of demand side management (DSM) initiatives to delay network upgrades and investments in constrained networks (Violette et al., 2006a, 2006b). Since the introduction of deregulation in the early 1990s, DSM investments by utilities have declined significantly, as utilities in restructured markets do not have financial incentives for investing in DSM in deregulated markets (Loughran and Kulick, 2004). Recent research has also indicated that historically low participation in time-differentiated pricing programs, as well as the low short-run price elasticity of demand, can result in potentially large social welfare losses in deregulated markets (Boisvert and Neenan, 2003). The welfare losses from low demand-response levels could be significantly reduced by introducing administered DR programs in concert with centralized energy spot markets.

In this paper, we consider demand response markets run by U.S. Regional Transmission Organizations (RTOs). These programs generally include subsidies of one sort or another. We examine whether these subsidies introduce net deadweight losses or other distortions into the energy market, or whether they instead help correct the market failure caused by treating load as completely price-inelastic.

We examine the economic social welfare of a DR program that allows end-use customers to reduce load in response to price signals. Our analysis focuses on one such program run by the PJM interconnection that can lower the peak demand in PJM through price responsive load curtailments. The PJM Interconnection supplies 50 million people in the United States, serving a peak load of 145,000 MW with 165,000 MW of generation, making it the world's largest electricity market. While average hourly electricity prices in PJM's real time market were between \$49/MWh and \$58/MWh during 2005-07, peak prices went above \$200/MWh for 35 hours in 2005, 2006 and 2007 (figure 1).

2. PJM's demand response programs

Nearly all RTOs in the United States have some form of a market that enables customers or load aggregators to bid in demand reduction (Walawalkar et al., 2007). These DR programs allow customers to participate directly in real time and day-ahead energy markets. PJM offers two types of DR programs:

Economic DR Program[1]: Under this program PJM pays the Locational Marginal Price (LMP) to customers if the LMP in a given zone is above a trigger point (set by PJM at $75/MWh). When the LMP is less than or equal to $75/MWh, PJM pays the customer the difference between the LMP and the generation and transmission (G&T) components of the customer's bill. PJM offers this economic DR program in both its day-ahead and real-time markets. A significant difference between the two is that there is no penalty for non-compliance in the real-time market, while successful bidding into the day-ahead DR market represents an obligation to curtail load.

[1] The economic demand response program incentive structure modeled in this paper was allowed to expire at the end of 2007. The subsidy payments described in this paper are no longer offered to DR market participants. The U.S. Federal Energy Regulatory Commission (FERC) upheld the expiration of the incentive payments in an order under Docket EL08-12-000, issued on 31 December 2007.

Emergency DR Program: This is a voluntary program for reliability that offers energy payments to customers that reduce load during a system emergency. The payments are the higher of $500/MWh or the zonal LMP for the hour. There is no penalty for non compliance, and this program is rarely utilized by PJM (on average, less than twice a year).

End use customers can participate in these DR programs by using either distributed generators or energy management control strategies to reduce their load in response to a price or emergency signal from PJM. Table 1 lists some of the control strategies used in economic or emergency DR programs.

During 2006, there was 1,475 MW load registered under the economic DR program and an additional 1,081 MW load registered under the emergency DR program (Kujawski, 2007). However, during the summer of 2006, there was only 325 MW of DR cleared in the economic DR program during the peak load days (Covino, 2006). Thus, a distinction must be made between loads that are registered to participate in the PJM demand response markets, and the amount of load that actually participates.

3. An economic model of the PJM demand response market

In contrast to existing work that assumes 3% to 10% DR participation (e.g. Brattle, 2007 and Boisvert and Neenan, 2003), our analysis of the PJM economic DR program is based on actual participation data. Since the "emergency" DR program is called on very rarely (Table 2), it is not discussed here.

As previously discussed, PJM's economic DR program offered incentives for participation in the form of payments related to the LMP at the time the demand curtailment occurs (which may be different than the time a customer commits to demand curtailment). Under the economic DR program, the incentive is available once the LMP exceeds some trigger point, which we denote as LMP*. In its economic DR program, PJM set LMP* equal to $75/MWh. The direct payment accruing to the *i*th market participant curtailing one megawatt of demand during hour t is given by:

$$(1) \qquad \pi_{it} = \begin{cases} LMP_t & LMP_t \geq LMP^* \\ \left(LMP_t - GT_i\right) & GT_i < LMP_t < LMP^* \\ 0 & GT > LMP_t \end{cases}$$

where GT is the sum of the generation and transmission (G&T) components of the customer's monthly electric bill.[2] The direct payment for a market participant curtailing $Q_{Ri,t}$ megawatts of demand during hour t is given by $Q_{Ri,t} \times \pi_{it}$. The R in the subscript denotes demand reduction rather than the level of demand.

The decision of an individual consumer or load aggregator to offer DR in the PJM market and the payment from actually curtailing demand do not occur simultaneously. In the day-ahead DR market, consumers bid binding demand-reduction commitments; the accepted curtailment bids must be honored 24 hours later. The real-time DR market operates differently. Each DR participant must notify PJM of their intent to curtail load at least one hour in advance. Load curtailment is compensated using the real-time LMP. The real time demand-reduction commitments are non-binding: consumers incur no penalty for shortfall in curtailment. Since the payment to the consumer depends on the prevailing LMP at the time that demand is actually curtailed, market participants are effectively basing a commitment to reduce demand at time t on an expectation of prices at some previous time $t – k$.

[2] The G&T component can vary significantly from year to year due to changes in fuel costs. G&T charges may be based on customer class, as well as historical retail rates. For some industrial customers the G&T component could be as low as $30 /MWh, while for other customers the G&T component may be indexed to day ahead or real time LMP.

Market participants must decide whether to bid any demand reduction into the market, and then must decide what kind of demand-response "supply curve" to bid into the market. The most significant factor in the decision to bid DR is the expectation of the market-clearing price in PJM. Figure 2 shows a price-quantity plot of actual market clearing bid data into the day-ahead and real-time PJM economic DR market (Covino, 2006). These data constitute the only price-quantity data released for PJM's economic DR program.

Although there was some DR activity below the incentive trigger point of $75/MWh, there is very little economic incentive for participation in the DR market at such low prices unless customers have low G&T rates. For example, if the LMP is $60/MWh and the customer's G&T rate is $50/MWh, the payment to the customer for providing DR services would be $60 - $50 = $10/MWh. When the LMP is lower than the G&T rate, a customer providing DR services to PJM receives no payment at all (equation 1). Part of the observed activity below the trigger point under the real time DR program can likely be explained by unanticipated variations in the real time LMP, where the LMP dropped below $75/MWh unexpectedly (that is, DR was bid into the market on the incorrect expectation that prevailing prices would be higher than $75/MWh)[3]. Note that the direct payment π_{it} represents a transfer payment to the ith participant in the DR market from the rest of the participants in the system (generators, other participants in the DR market, and energy-market customers that do not offer demand response). However, even small amounts of DR may provide large benefits to the system as a whole. Thus, even though DR market participants receive subsidies, there are large positive externalities from DR (since prices

[3] It is also possible that some of the response at low prices resulted from attempts at strategic bidding into the DR market by taking advantage of loopholes in the Customer Base Line (CBL) methodology used to determine the amount of load curtailments on a given day. PJM has recently taken steps to strengthen the CBL methodology to prevent such actions. The CBL methodology is outlined in PJM Manual 11 (PJM, 2008)

are also lowered for those who do not curtail their demand). These positive externalities amount to a transfer of economic surplus from generators to those who do not curtail demand.

More generally, we may break down the economic effects of the PJM DR program into four components, which are explained below and shown graphically in figure 3 (Brattle, 2007 and Boisvert and Neenan, 2003).

Area A: A transfer of producer surplus (short-run profit) to consumers who do not curtail their demand. We use the term "transfer" here to indicate that the short-run profit lost by generators (due to the fact that DR causes prices to fall) is a direct benefit to consumers who do not curtail any demand, since they are able to enjoy their usual amount of electricity consumption at lower prices. The magnitude of the transfer is given by $Q'' \times \Delta LMP(Q)$, where Q'' is the amount of demand in the system after DR market participants have curtailed their loads, and $\Delta LMP(Q)$ is the change in LMP resulting from $(Q' - Q'')$ MW of demand being curtailed, that is, $\Delta LMP(Q) = LMP' - LMP''$. This transfer is area A in figure 3.

Area B: A transfer from generators to price-responsive consumers. This transfer is conceptually similar to the transfer in area A, but represents the benefit enjoyed by price-responsive customers due to lower energy prices. This transfer is equal to

$(Q' - Q'') \times LMP' - \int_{Q''}^{Q'} MC(Q)dQ$, area B in figure 3, where *MC(Q)* is the short run marginal cost (MC) electric supply curve for the PJM market.

Area C: A gain in social welfare (benefits that accrue to both consumers and generators) equal to $\int_{Q''}^{Q'} LMP(Q_s)dQ_s - \int_{Q''}^{Q'} LMP(Q_d)dQ_d$, where $LMP(Q_d)$ is the DR supply curve for those consumers participating in the DR market and $LMP(Q_s)$ is the LMP curve in the energy market. This social welfare gain is area C in figure 3.

Area D: An amount $(Q'-Q'')\times GT$, representing the incentive payment. This represents a transfer from consumers who do not participate in the DR market to consumers who do participate in the DR market. Other things being equal, the incentive payment will persuade some consumers to participate in the DR market that would not have participated with energy price signals alone. Thus, the incentive payment may be viewed as a subsidy.

Figure 3 illustrates that the DR program described here will convey a net social benefit if the social welfare gain is larger than the incentive payments (that is, if area C is larger than area D). Note that our analysis of the PJM DR incentive is somewhat different than the analysis described in (Boisvert and Neenan, 2003), which examined a DR program where the incentive payment is equal to $\int_{Q''}^{Q'} LMP(Q)dQ$, or the entire area under the price-responsive portion of the demand curve between Q'' and Q' in figure 3. Our simulation procedure also differs from that of The Brattle Group (2007), who use a proprietary market simulation tool to produce simulated prices with and without demand response. The analysis in figure 3 is a short-run welfare analysis, and implicitly assumes that all participants in the DR market are sufficiently small that individually they cannot influence the market-clearing price. The incentive payments given to DR market participants are funded by additional charges paid by load serving entities, based on their share of load in the zone where load is reduced. These fees likely introduce distortions and deadweight losses elsewhere in the market that are not captured in the partial equilibrium analysis presented here (although we use the total incentive payment as a proxy for these deadweight losses). Thus, our analysis likely overstates the net social benefits of PJM's DR program, though the deadweight losses not considered are likely to be small. Using the data shown in figure 2, we estimate the sloped portion of the demand curve shown in figure 3. Data released by PJM indicates that the maximum amount of participation in PJM's economic DR program in any given hour during the summer of 2006 was 325 MW. Using these data, we calculated three DR supply curves, as shown in figure 2. The curves we estimate are given by:

$$LMP''_t = 0.01 \times (Q'_t - Q''_t) + LMP^* \tag{2}$$

$$LMP''_t = 0.15 \times (Q'_t - Q''_t) + LMP^* \tag{3}$$

$$LMP''_t = 0.54 \times (Q'_t - Q''_t) + LMP^* \tag{4}$$

The purpose of choosing the three different DR supply slopes is to provide a sensitivity analysis to demonstrate the social welfare implications of a higher or lower price elasticity of demand. Participation in PJM's economic DR program amounted to only 0.2% of peak demand in 2006. In our simulations, we estimate the impact of DR representing up to 5% of peak demand, using the three slopes illustrated in figure 2. This upper bound on DR is chosen to be consistent with assumptions used elsewhere in the literature (e.g., Boisvert and Neenan 2003; Brattle Group 2007), and allows us to calculate the net social benefits or costs of expanding PJM’s existing DR programs. We thus set a maximum DR participation limit of 7500 MW (assuming a PJM peak load of 150,000 MW); we note that this level of DR was attained only with our most price-elastic DR supply curve (equation 2).

4. Simulation procedure and estimated prices

For each hour of 2006, we used the actual load duration curve and an econometric model of LMPs for the PJM market to estimate the four regions shown in figure 3. We perform simulations using each of the three DR supply curves shown in equations (2) – (4) as well as a number of different trigger points, LMP^*_j where j denotes the individual trigger point. The goal is to compare the social welfare gain from the DR program (area C) to the subsidy payment given to DR market participants (area D). Our simulation procedure takes the following steps:

1. For each hour t, each DR supply-curve slope α_k, and each trigger point LMP^*_j we calculate the amount of DR in the market by solving equations (2) – (4) to get:

$$DR_{t,j,k} = \begin{cases} \min\left((LMP''_t - LMP^*_j)/\alpha_k, 7500\right) & \text{if} \quad LMP''_t \geq LMP^*_j \\ 0 \quad \text{if} \quad LMP''_t < LMP^*_j, \end{cases} \tag{5}$$

where $DR_{t,j,k}$ is the amount of demand response that clears the market in hour t, with DR supply-curve slope α_k and trigger point LMP^*_j, and LMP''_t is the actual LMP in hour t. For hours where $LMP''_t < LMP^*_j$, demand response is not profitable, so we assume that $DR_{t,j,k} = 0$ for those hours. For our simulations to be consistent with others in the literature, we impose a ceiling on demand response of 7500 MW for those hours where $LMP''_t \geq LMP^*_j$. 7500 MW is approximately 5% of the 2006 PJM peak system load. Table 4 shows the highest value of $DR_{t,j,k}$ that clears the market for each year, DR supply-curve slope α_k and trigger point LMP^*_j. In our simulations we consider values for the slope of the demand-response supply curve α_k ={0.01, 0.15, 0.54} and value of the trigger point LMP^*_j ={\$50, \$60, \$70, \$75, \$80, \$90, \$100}.

2. For each hour t, DR supply-curve slope α_k and trigger point LMP^*_j, we calculate:

$$Q'_{t,j,k} = Q''_t + DR_{t,j,k} \tag{6}$$

where $Q'_{t,j,k}$ is the PJM system load in hour t, with DR supply-curve slope α_k and trigger point LMP^*_j in the absence of demand response, and Q''_t is the actual PJM system load in hour t. That is, the amount of DR from step one is added to the actual PJM system load from hour t, yielding an estimate of what the system load would have been in the absence of demand response.[4]

3. For each hour t, DR supply-curve slope α_k and trigger point LMP^*_j, we calculate an estimate of what the LMP would have been in the absence of DR ($LMP'_{t,j,k}$) using a statistical model of LMP (see below for details).

4. For each hour t, DR supply-curve slope α_k and trigger point LMP^*_j, we calculate the areas of the four regions shown in figure 3. Note that in steps one through four we have defined $Q''_{t,j,k}$, Q'_t, $LMP'_{t,j,k}$ and LMP''_t so as to be consistent with the nomenclature in figure 3 and equations (2) through (4).

In step three of the simulation procedure, we employed a statistical model to estimate what the LMP would have been in the absence of demand response. Our model uses hourly demand and price data from the PJM real-time energy market in 2006. We model the hourly LMP in PJM as a sixth-degree polynomial function of load. Following Allen and Ilic (1999), we model the error term as following a first-order autoregressive process (AR(1) process). We also include fixed effects for each hour of the day, to capture variations between peak and off-peak periods. The model we estimate takes the form:

$$(7)\quad LMP_t = \alpha + \beta_1 Load_t + \beta_2 Load_t^2 + \beta_3 Load_t^3 + \beta_4 Load_t^4 + \beta_5 Load_t^5 + \beta_6 Load_t^6 + \varphi LMP_{t-1} + \Sigma_i \gamma_i Hour_{it} + \varepsilon_t,$$

where $Load_t$ is the real-time PJM load during hour t, LMP_{t-1} is the real-time LMP from the previous hour, the $Hour_{it}$ variables represent the time-of-day fixed effects, and ε_t is the AR(1) error term.

[4] Technically, we are interpreting Q'_t only as a base-case system load for the purposes of our simulation. We use actual hourly data from the PJM real-time energy market for Q''_t and LMP''_t. These data incorporate the amount of demand response that cleared the market in each hour at a trigger point of $75/MWh.

The estimated parameters of our model are shown in Table 3. All variables in the model were statistically significant at the 5% level. The R^2 of the model was 0.75, and the model's standard error is 306.2.

5. Simulation results and discussion

Based on our simulations, we calculate areas A through D for each hour of 2006. The annual total of each area's calculation for 2006 is shown graphically in figure 4, for each assumed slope and each assumed trigger point. Summary data for the total amount of DR modeled is shown in Table 4, while the results of our welfare calculations are summarized in Table 5. Area B is omitted from figure 4 since it is small in magnitude compared to the others (Table 5).

The largest economic impact from PJM's DR market is a transfer of wealth from generators to those who do not participate in the DR program (area A in figure 3). In 2006, we estimate the value of these transfers could have been between \$18 million and \$561 million, depending on the slope of the DR supply curve, and assuming a trigger point of \$75/MWh. This wealth transfer increases as the trigger point decreases (since a lower trigger point can be expected to draw more DR into the market).

Our simulations also indicate that the maximum amount of DR depends on both the slope of the DR supply curve and the incentive trigger point, LMP*. Table 4 shows the maximum amount of DR that can be cleared under different DR supply curves and different incentive trigger points. Unsurprisingly, low trigger points and more elastic demand will produce larger amounts of DR in our model.

Figure 4 suggests a range for which the social welfare gain from DR (area C in figure 3) will outweigh the distortions due to the subsidy (area D). In general, the annual subsidy payments tend to be greater than the net social benefit if the incentive trigger point is too low. This crossover point (where the social benefit is equal to the subsidy) occurs at a higher incentive trigger point for those DR supply curves that have lower slopes. The crossover point occurs at $66/MWh for our DR supply curve with a slope of -0.54. For the DR supply curve with slope of -0.01 the crossover point occurs at $77/MWh.

This analysis also indicates that with LMP* equal to $75/MWh (as in PJM's economic DR program as it existed prior to 2008), for the DR supply curve with a slope of -0.15, our estimate of the net social welfare gain exceeds the total subsidy payments by $2.6 million. For the same value of LMP* and DR supply curve with a slope of -0.54, our estimate of the social welfare gain exceeds the total subsidy payments by $0.6 million. The subsidy payments exceed the estimated net social welfare by $7.2 million for the DR supply curve with slope of -0.01. Table 5 summarizes the effect of DR supply curve slopes and incentive trigger points on net social welfare, transfer payments from generators to load and subsidy payments to DR providers.

Tables 4 and 5 indicate that for a DR supply curve with a slope of -0.15 and LMP* equal to $75/MWh, the total transfer payments to load (areas A and B) during 2006 would be $70 million with a maximum of 3,246 MW of DR participating in the market. PJM (Ott, 2007) reports significantly larger energy payment reductions due to DR ($650 million during a one-week heat wave in August 2006), but their calculations likely differ from ours since PJM allows generators to charge above-market prices during periods when reliability may be threatened. The appendix discusses the effect of including this "scarcity pricing" on the net social welfare and transfer payments.

6. Effect of the incentive structure on individual DR participants

Most of the DR participation in PJM's economic DR program is through curtailment service providers (CSPs), who act as DR aggregators, and facilitate DR participation in PJM's program. The principal service provided by these CSPs is to reduce the transactions costs (such as fees for market participation, gathering information and actually submitting bids) associated with participating in PJM's DR market. Since increased participation in the PJM economic DR market improves social welfare for the system (as discussed above), the operating environment for CSPs becomes an important policy variable. In this section we extend our economic analysis of PJM's DR programs to consider the participation incentives (that is, the revenue stream) for individual loads or load aggregators. Although an individual customer's decision to offer DR to the market is based on marginal revenue for a particular operating hour, CSPs must also evaluate the annual revenue potential for their own business model.

We calculate the maximum annual DR payment that could be earned by a DR participant in PJM using hourly LMP data from 2004 through 2007. We assume that each customer decides upon some "strike price" at which she is willing to participate in the DR market. The strike price is equivalent to the offer price submitted by a DR market participant in the day ahead or real time energy market. We do not attempt to explain the factors that might influence this strike price directly, but we note that since the strike price represents both the actual cost and opportunity cost of providing load curtailment, it will vary among individual DR participants and even among load aggregators. Figure 5 shows a sensitivity analysis of the expected revenues during 2004-07 from participating in the PJM economic DR market, as a function of an individual participant's strike price. As an illustration, in 2005 (the year with the most number of hours when the LMP was above any selected strike price in our sample) a customer with a strike price of $75/MWh would have earned approximately $240,000 / MW; a customer with a strike price of $100/MWh would have earned $145,000/ MW; a customer with a strike price of $150/MWh would have earned $42,000/ MW; and a customer with a strike price of $200/Mwh would have earned $8,000 /MW.

These estimates suggest upper limits for the gross revenues from DR program participation, assuming sufficient flexibility (that is, the customer can reduce demand during all hours in which the LMP exceeds her strike price). Note that we do not include any direct costs incurred through demand response program participation (such as the costs of load curtailment, payments to load aggregators or the opportunity costs of time spent submitting bids and processing information), so these figures should not be interpreted as profits or net benefits. A change in the incentive structure of the PJM economic DR program will affect the gross revenues or benefits from participation. This is shown in figure 6 for the case of the subsidy payment (area D in figure 3) being eliminated. A customer who offers load curtailment with a strike price of $75/MWh would have received less than $130,000 / MW in annual revenues in 2005 (without the subsidy payment) as compared to $240,000 under the original incentive structure as described in equation 1. The total revenue potential with and without incentive payments is summarized in Table 7. Note that some of the large jumps in gross benefits occur because the distribution of PJM LMPs is heavily skewed (prices in the PJM market get very high in only a small number of hours; in the short run, this is a characteristic of most energy commodity markets), as shown in figure 7.

If the incentive payments for DR participation are eliminated, some potential participants may increase their strike price so that the marginal payments from DR program participation are equalized with and without the incentive payment. For instance, customers with a G&T rate of

\$50/MWh may change their strike price from \$75/MWh to \$125/MWh when the incentive is removed.[5]

The benefits to an individual customer from demand-response participation will depend not only on the strike price and incentive structure, but also the distribution of market prices. We incorporated uncertainty due to fluctuations in energy prices from year to year into our analysis by performing a Monte Carlo simulation on the expected annual DR revenue stream, using DR market data from 2004 – 2007. We modeled annual revenues based on participant strike prices, with and without the DR market incentives. For each year t and strike price k, we assumed that annual revenues π_t follow a triangular distribution with the minimum value equal to the sum of hourly revenues in 2004 (the lowest revenue year in our sample), the maximum equal to the sum in 2005 (the highest), and the most likely value equal to the average of the four years. We generated 1000 realizations of the discounted present value of expected annual revenues over a five-year time horizon, assuming a customer with an internal discount rate of 10%; we did this for a \$75 strike price with the incentive per equation 1, for a \$75 strike price without the incentive and for a \$125 strike price without the incentive (the latter two were done by setting π_t = (LMP_t – GT) for LMP_t, ≥ strike price and zero for LMP_t < strike price).

These simulation results are shown in figure 8. A demand response market participant offering load curtailment at \$75/MWh would receive a discounted gross revenue stream of \$610,000 over five years with a 50% probability. On the other hand, if the incentive payment is removed, forcing the customer to adjust her strike price to \$125/MWh (to receive the DR payment of \$75/MWh), then the NPV would fall by roughly a factor of five, to \$107,000.

[5] Without the knowledge of each participant's marginal cost of providing DR, it is not clear that increasing the reservation price in this way represents an optimal strategy from a profit or utility-maximization perspective. Based

7. Conclusion

During peak periods, even very small decreases in demand can yield very large decreases in LMP. Since RTO markets in the U.S. are highly integrated and operate as uniform-price auctions, load curtailment by one party can provide large benefits (in the form of price reduction and perhaps increased reliability) to consumers who do not participate in RTO DR markets or are otherwise non price-responsive.

Centralized DR markets operated by RTOs often include subsidy payments to those who voluntarily curtail load, introducing market distortions associated with these incentives. We simulate load curtailment in the PJM market based on actual DR market result data under a number of different assumptions about the incentive program and the responsiveness of customers.

We find that for recent levels of the incentive payment, the social welfare gains exceed the total annual subsidy payments. Thus, PJM's economic DR program as it existed prior to 2008 provided a net benefit to the system.

The subsidy payments in the PJM DR program acted to correct two market failures associated with the spot energy markets in RTOs. The first is the treatment of all demand as price-inelastic, which leads to deadweight losses in the market since resources (particularly during peak periods) are not dispatched in a way that equates marginal generator cost with marginal customer benefits. The second market failure is the temptation to free-ride in load curtailment. Our simulations suggest that the wealth transfers associated with DR (particularly to non price-responsive load) are quite large compared to the gains to price-responsive load. The disparity between individual benefits and system benefits implies that, left to its own devices, the

on personal communications with participants in load curtailment programs, the strategy of increasing the

PJM energy market is likely to under-provide demand response relative to the socially optimal point. The incentive payment provides a mechanism for correcting this externality.

The welfare impact of demand response is affected by the slope of the DR supply curve. Thus, the structure of a DR program can influence the program's outcome. For many customers, DR achieved through energy management and automated control systems can help to achieve load reduction goals at a reasonably low marginal cost as compared to load reduction through distributed generation (which potentially exposes customers to fuel price volatility). From the perspective of the system, both distributed generation and energy management can help achieve DR goals, but programs that can increase the price elasticity of demand will offer higher system-level benefits.

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reservation price does appear prevalent.

Appendix: Effects of Scarcity Pricing

Starting in 2006, the Federal Energy Regulatory Commission (FERC) allowed PJM to permit generators to earn super-competitive rents (and thus avoid bid or price mitigation by market monitors) during periods where system reliability is threatened. The mechanism allowed by FERC for generators to capture these rents is known as "scarcity pricing." When scarcity pricing is triggered in a given region of PJM, the market-clearing price in the entire region will be set equal to the highest market-based offer price of *any* generating unit dispatched by PJM (PJM 2006). An overall cap on scarcity prices is set at $1,000 per megawatt-hour, but the rule does permit infra-marginal generators to earn higher profits than the energy market would normally allow.

Based on the price duration curve for 2006-2007 (figure 1), we modified our model to simulate the effects of avoided scarcity pricing during the highest priced 15 hours. For these 15 hours, instead of using LMPs predicted by equation 7, market prices in the absence of DR were set equal to the scarcity price cap of $1000/MWh. Our results, shown graphically in figure 9 and summarized in Table 7, suggest that PJM's scarcity pricing provision lowers the incentive trigger point at which the social welfare gains from the PJM economic DR program equal the subsidy payments made under the program. For example, figure 9 shows that when the effect of scarcity pricing is considered, the point where the social benefit is equal to the subsidy occurs at $51/MWh for a DR supply curve with a slope of -0.54. For the DR supply curve with a slope of -0.01 the crossover point occurs at $66/MWh. These represent a shift of -$11 to -$15/MWh from the model without scarcity pricing.[6]

[6] According to an internal cost benefit analysis performed by PJM staff the system wide benefits exceed the cost of DR program when the LMP* is set at $58/MWh for the day ahead economic demand response program (FERC, 2007).

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Table 1: Control Strategies for participation in DR programs for different customer types (Adapted from Walawalkar et al. 2007)

Customer Type	Equipment / Building Component	Control Strategy
Residential	Air Conditioners	Cycling/forced demand shedding
	Water Heaters	Cycling
	Pool Pumps	Cycling
	Electric Stoves	Scheduling
Commercial	Chillers	Demand limiting during on peak period
	Chillers	Pre-cool building for over-night storage
	HVAC	Direct expansion (DX) forced demand scheduling
	Refrigerator/Freezers	Prioritized demand shedding
	Lighting	Scheduled on/off
	Lighting	Scheduled dimming of selected circuits
Industrial	Chillers	Demand limiting on time schedule
	Electric Furnaces	Demand limiting through heat stages
	Electric Furnaces	Curtail (during peak period)
	Variable Speed Drives	Limit output on scheduled basis
	Well pumps	Defer during peak
	Production Equipment	Prioritized demand on selected units
Restaurants / Shopping Malls	HVAC	Chillers- demand limiting during peak
	DX Compressors	Forced demand shedding of multiple units
	Refrigerator/Freezers	Prioritized demand shedding
	Electric Stoves	Scheduled pre-cooking

Table 2: Summary of PJM initiated emergency DR events (Source: PJM, 2007)

Year	**No of events**	**Dates**
2000	2	May 8th and May 9th
2001	4	July 25th, August 8th, 9th and 10th
2002	3	July 3rd, 29th, 30th
2003	0	None
2004	0	None
2005	2	July 27th, Aug 4th
2006	2	Aug 2nd, 3rd
2007	1	Aug 8th

Table 3: Parameter Estimates from the Econometric LMP Model

Variable	Est. Parameter		T-Statistic
Constant	1,917.98	**	4.04
Load	-0.15	**	-4.35
Load^2	$< 10^{-21}$	**	4.65
Load^3	-7.55×10^{-11}	**	-4.97
Load^4	6.81×10^{-16}	**	5.31
Load^5	-3.21×10^{-21}	**	-5.67
Load^6	-6.18×10^{-11}	**	6.06
LMP(t-1)	0.68	**	121.63
Hour 1	2.75	**	2.97
Hour 2	5.72	**	6.12
Hour 3	4.30	**	4.57
Hour 4	5.20	**	5.51
Hour 5	7.69	**	8.17
Hour 6	12.34	**	13.29
Hour 7	20.04	**	21.80
Hour 8	9.64	**	10.48
Hour 9	9.64	**	10.48
Hour 10	11.15	**	12.10
Hour 11	12.04	**	13.06
Hour 12	8.31	**	9.00
Hour 13	9.09	**	9.86
Hour 14	10.33	**	11.20
Hour 15	7.69	**	8.33
Hour 16	7.93	**	8.60
Hour 17	12.74	**	13.81
Hour 18	14.00	**	15.14
Hour 19	5.43	**	5.85
Hour 20	6.61	**	7.14
Hour 21	11.06	**	11.94
Hour 22	1.91	*	2.07
Hour 23	-8.72	**	-9.45
AR(1)	0.03	**	3.97

R^2: 0.75

S.E.: 306.2

*Note: ** = statistically significant at the 1% level*

** = statistically significant at the 5% level*

Table 4: Maximum amount of demand response cleared based on different DR supply curves and DR incentive trigger points

	Maximum DR (MW) at various DR Incentive Trigger Points						
DR Slope	**$50**	**$60**	**$70**	**$75**	**$80**	**$90**	**$100**
0.54	948.1	929.6	911.0	901.8	892.5	874.0	855.5
0.15	3413.1	3346.4	3279.8	3246.4	3213.1	3146.4	3079.8
0.01	7500.0	7500.0	7500.0	7500.0	7500.0	7500.0	7500.0

Table 5: Summary of effect of DR supply curve and LMP on net social welfare, transfer payments and incentive payments (without considering scarcity pricing rules)*

		Trigger Point LMP*						
	Area	**$50**	**$60**	**$70**	**$75**	**$80**	**$90**	**$100**
DR Slope 0.54	**A**	$25.0	$21.6	$19.2	$18.3	$17.5	$16.1	$15.0
	B	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
	C	$4.8	$4.0	$3.4	$3.1	$2.9	$2.5	$2.2
	D	$8.0	$4.9	$3.1	$2.5	$2.0	$1.4	$1.0
DR Slope 0.15	**A**	$95.2	$82.4	$73.5	$70.0	$67.0	$61.7	$57.3
	B	$0.5	$0.5	$0.5	$0.4	$0.4	$0.4	$0.4
	C	$17.7	$14.9	$12.5	$11.5	$10.6	$9.2	$8.1
	D	$28.6	$17.5	$11.1	$8.9	$7.3	$5.0	$3.7
DR Slope 0.01	**A**	$853.8	$698.8	$598.1	$561.2	$530.4	$483.8	$449.3
	B	$19.8	$16.6	$14.5	$13.8	$13.1	$12.1	$11.4
	C	$183.5	$145.4	$114.0	$101.2	$90.2	$73.4	$62.1
	D	$395.3	$232.8	$139.2	$108.4	$84.8	$53.4	$35.8

Note: All figures are in millions of dollars

Table 6: Change in annual DR revenue potential due to removal of incentive payments

Strike Price ($/MWh)	Revenues with incentive ($/MW-Year)			Revenues w/o incentive ($/MW-Year)			% Change		
	2004	2005	2006	2004	2005	2006	2004	2005	2006
$75	$74,833	$239,682	$133,755	$33,433	$129,682	$69,705	-55%	-46%	-48%
$100	$18,109	$145,244	$64,522	$10,209	$89,944	$40,972	-44%	-38%	-36%
$125	$4,164	$79,254	$31,851	$2,664	$53,704	$23,151	-36%	-32%	-27%
$150	$805	$41,925	$18,551	$555	$30,075	$14,751	-31%	-28%	-20%
$200	$-	$8,165	$11,661	$-	$6,315	$9,911	-	-23%	-15%

Table 7: Summary of effects of DR supply curve and LMP on net social welfare, transfer payments and incentive payments (with scarcity pricing rules)*

		Trigger Point LMP*						
	Area	**$50**	**$60**	**$70**	**$75**	**$80**	**$90**	**$100**
DR Slope 0.54	**A**	$1,765.4	$1,762.3	$1,760.2	$1,759.5	$1,758.8	$1,757.8	$1,757.0
	B	$2.9	$2.8	$2.7	$2.6	$2.5	$2.4	$2.3
	C	$7.7	$6.8	$6.0	$5.7	$5.4	$4.9	$4.5
	D	$8.0	$4.9	$3.1	$2.5	$2.0	$1.4	$1.0
DR Slope 0.15	**A**	$1,804.3	$1,793.0	$1,785.5	$1,782.7	$1,780.3	$1,776.4	$1,773.3
	B	$10.6	$10.1	$9.7	$9.5	$9.2	$8.8	$8.3
	C	$27.7	$24.5	$21.7	$20.5	$19.4	$17.6	$16.1
	D	$28.6	$17.5	$11.1	$8.9	$7.3	$5.0	$3.7
DR Slope 0.01	**A**	$2,420.7	$2,265.8	$2,165.1	$2,128.3	$2,097.6	$2,051.2	$2,016.8
	B	$64.1	$61.0	$58.7	$57.7	$56.9	$55.5	$54.3
	C	$227.9	$189.7	$158.2	$145.2	$134.0	$116.7	$105.0
	D	$395.3	$232.8	$139.2	$108.4	$84.8	$53.4	$35.8

Note: All figures are in millions of dollars

Illustrations

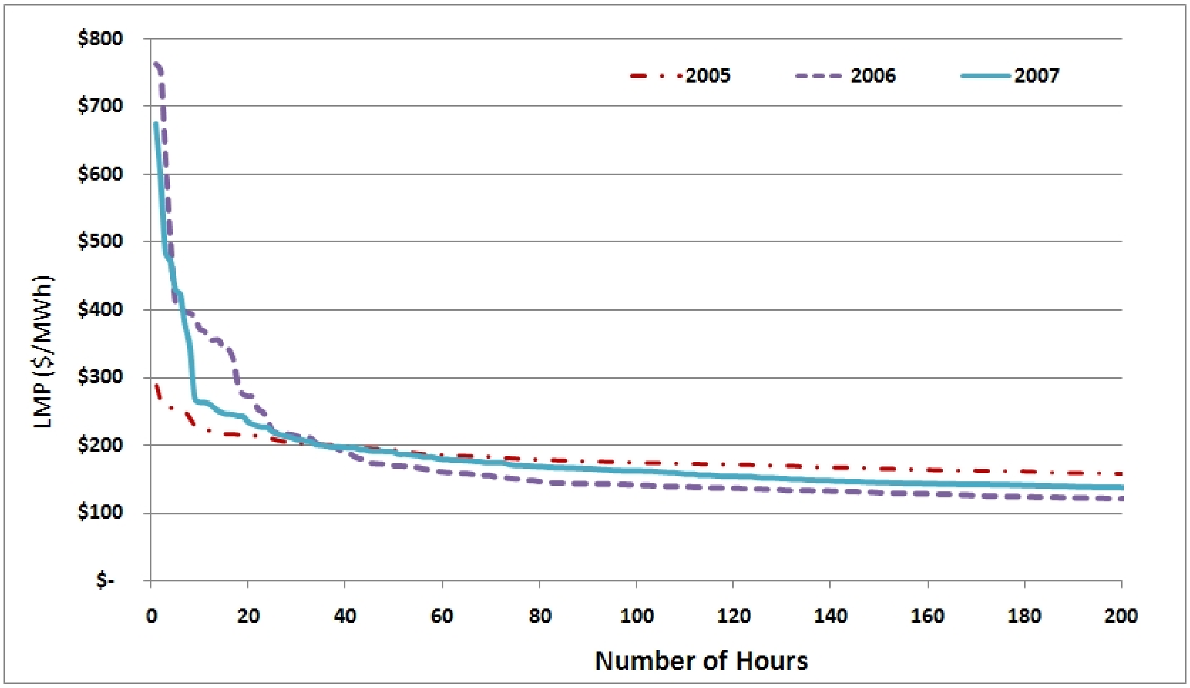

Figure 1: Price duration curve for the real-time market in PJM, top 200 hours (2005-07). Source: PJM Daily Real-Time Locational Marginal Pricing Files.

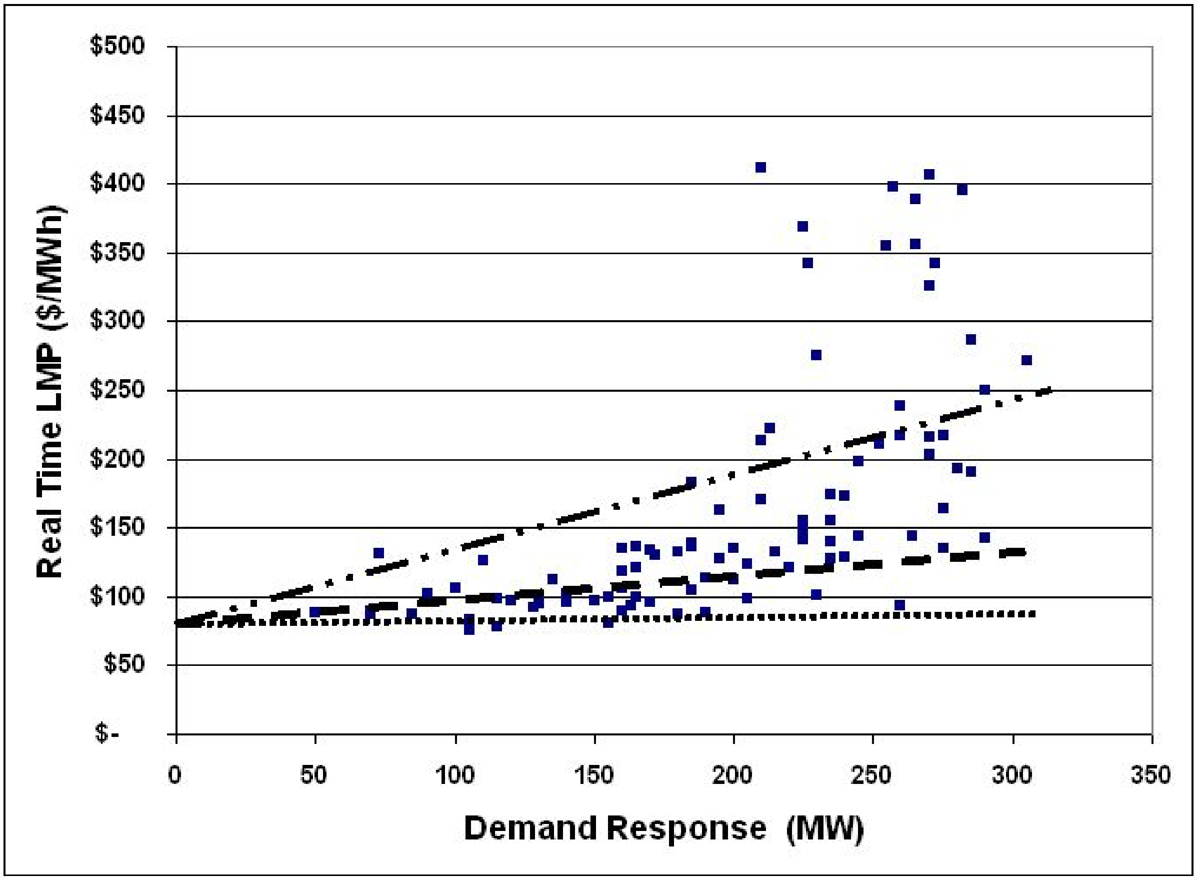

Figure 2: Load curtailment market results from the PJM economic demand response market during six days in 2006 and three possible DR supply curves Source: Covino, 2006.

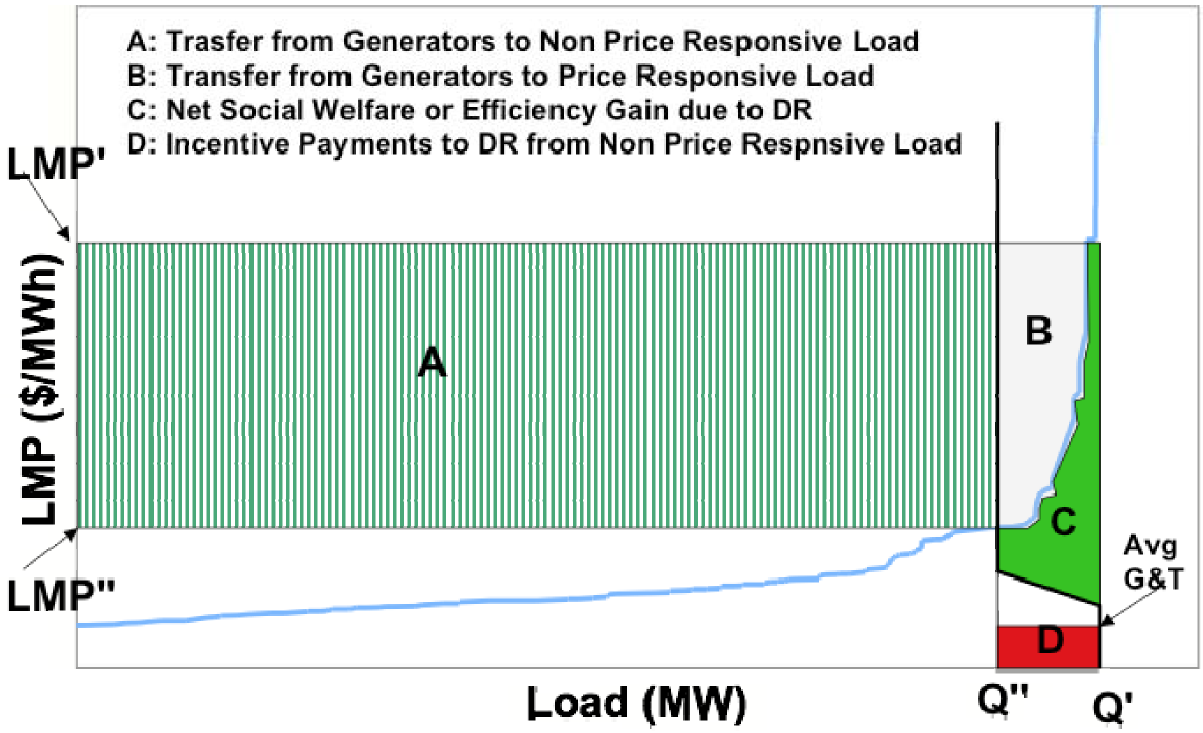

Figure 3: Conceptual framework for analysis of the PJM economic demand response program. The grey curve is the short run marginal cost curve for electric generation. The black curve is the demand curve, with the sloped portion representing demand response.

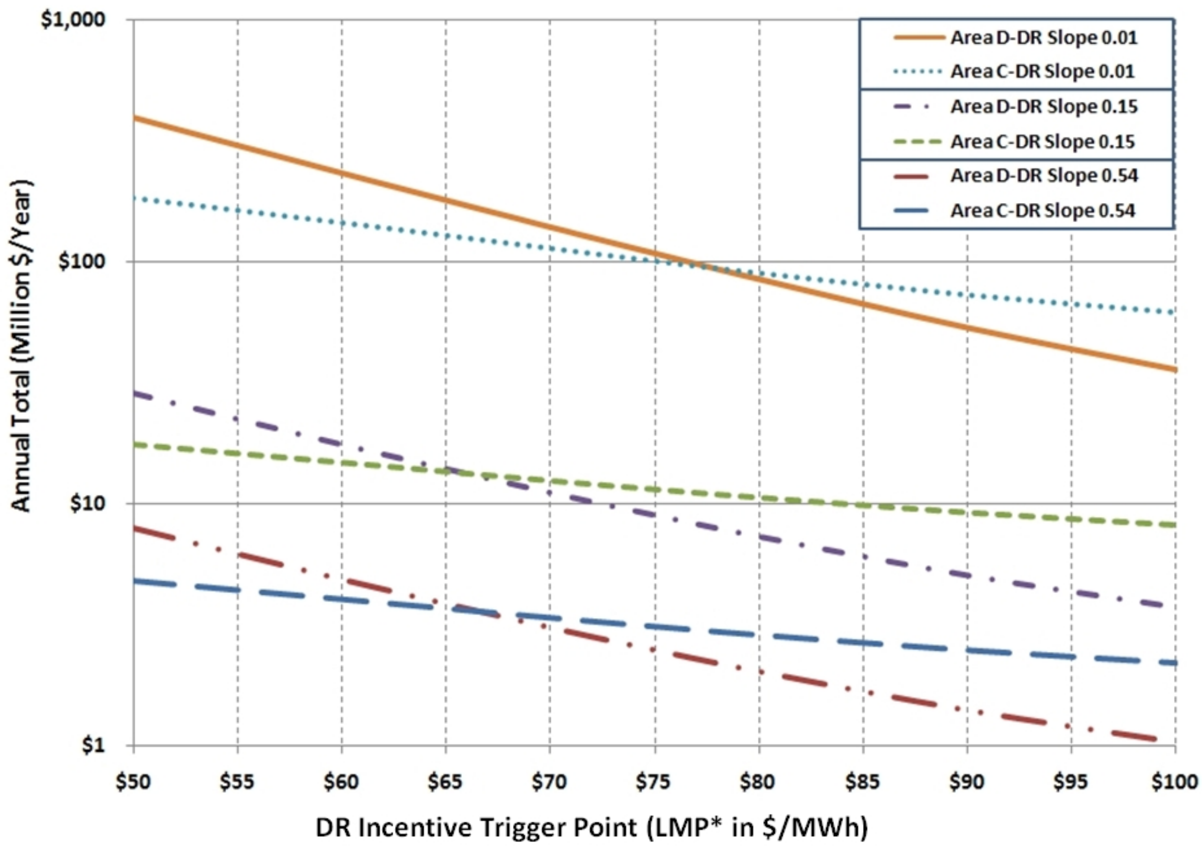

Figure 4: Effect of DR supply curve and LMP* on net social welfare and incentive payment (without considering scarcity pricing rules).

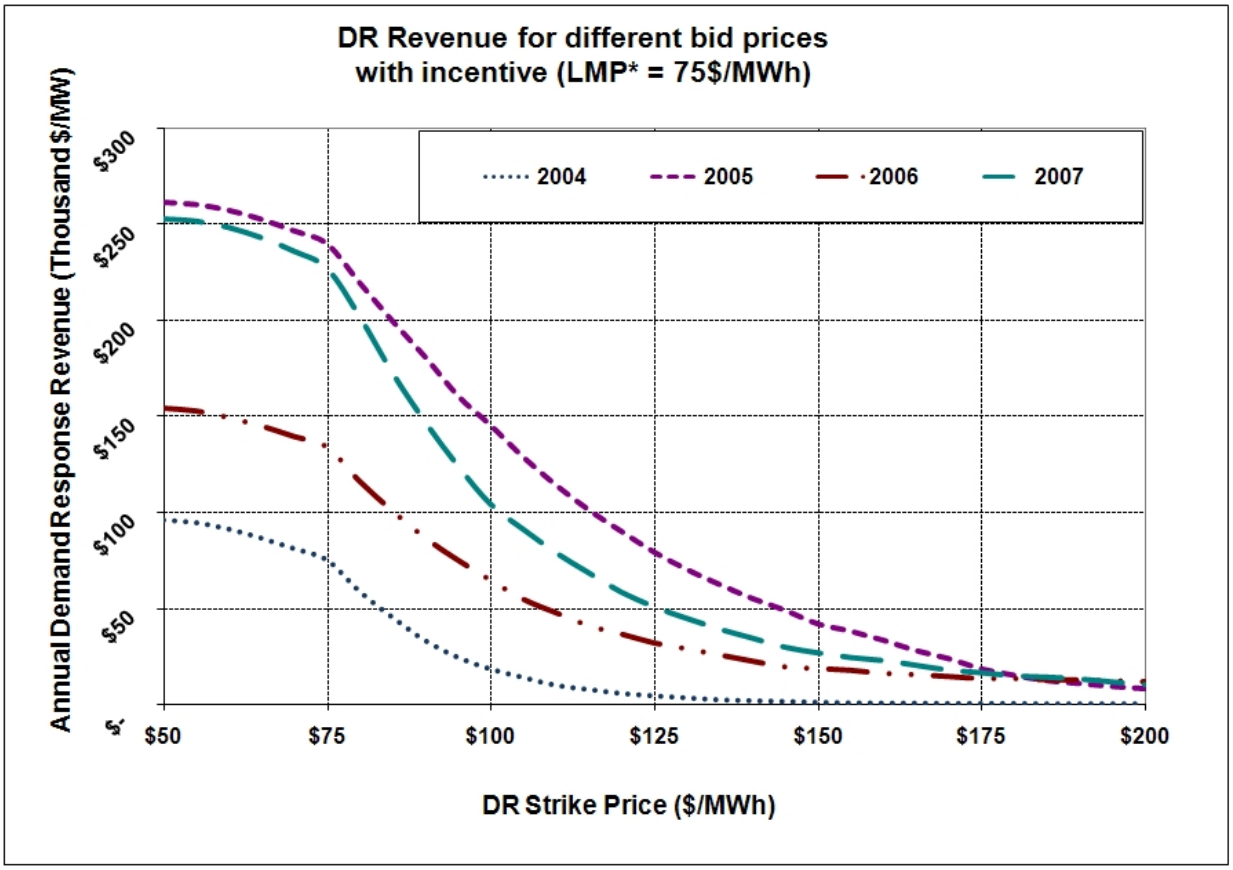

Figure 5: Expected real time DR revenue with the incentive structure as it existed prior to 2008 (LMP* = 75 $/MWh).

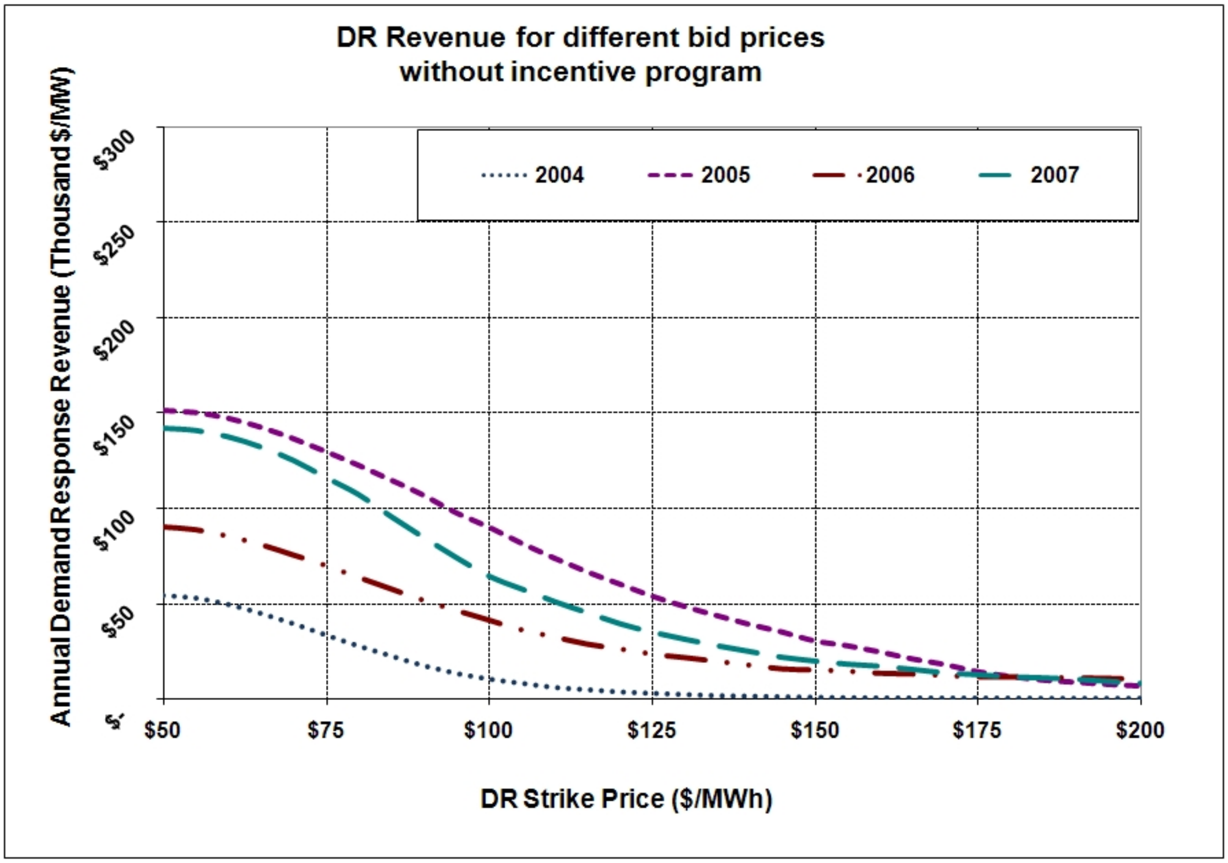

Figure 6: Expected real time DR program revenue without incentive .

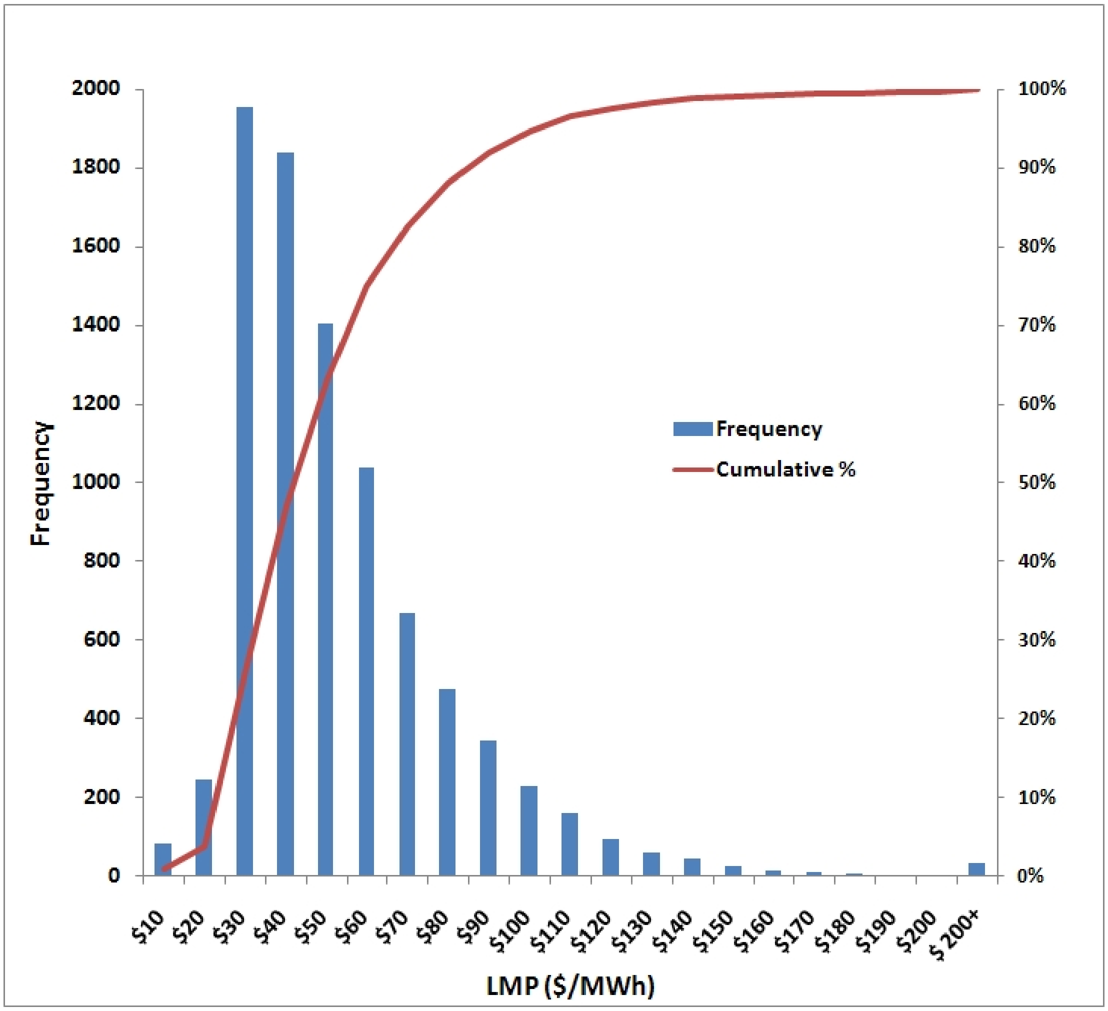

Figure 7: Histogram and cumulative distribution function of PJM LMPs in 2006.

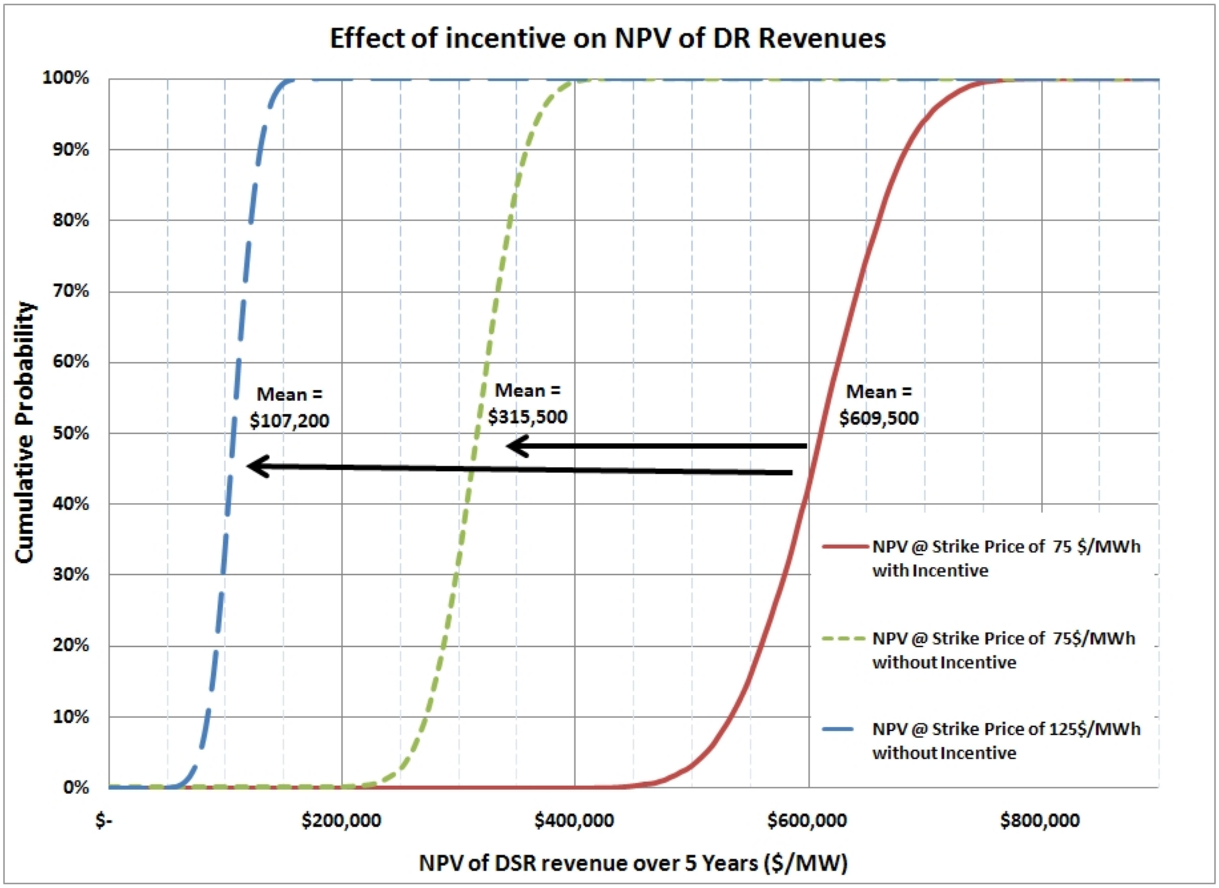

Figure 8: Cumulative probability of expected net present value of DR program revenue over 5 years under three incentive structures.

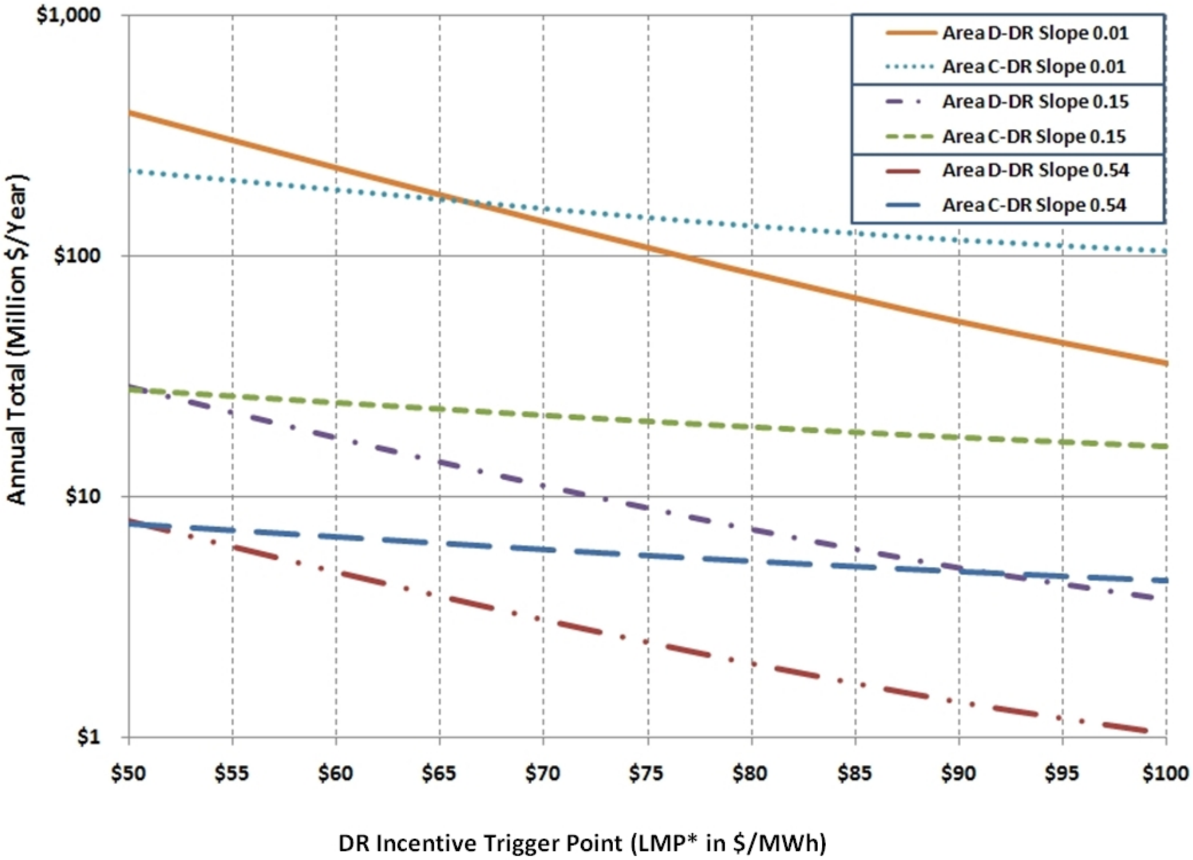

Figure 9: Effect of DR supply curve and LMP* on net social welfare and incentive payment (using PJM's scarcity pricing rules).