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# Mid-Atlantic States Cost Curve Analysis

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## Introduction

This report was prepared to analyze the impact of load reduction on reducing the cost of electricity in the context of the PJM utility system. In essence, when consumption is reduced, particularly during peak periods, the market price of electricity is reduced for all consumers. The consumers who reduce their usage receive the benefit of reducing their total consumption multiplied by the market price (with a real time pricing meter), or the load reduction multiplied by a monthly average price (for load-profiled customers), even though they are providing greater benefits to the system as a whole.

To undertake this quantitative analysis, it is first necessary to estimate a supply or cost curve for the PJM market using econometric techniques. That supply curve then becomes the basis for analysis of the relationship between the market price and the value of load reduction at various load levels, by time-of-use period, and for various types of conservation or distributed generation with specialized load shapes.

The value of load reduction was found to be about 24 cents/kWh on summer weekday afternoons in the year 2000 – compared to a market price of 5 cents/kWh.<sup>1</sup> In other summer heavy load hours (6am-10pm except peak hours), load reduction was worth almost 14 cents, with a market price of 4 cents/kWh. Off-peak and in the winter, the value of load reduction was less, but still ranged from 3.5 to 6 cents/kWh, with market prices in the range of 1.5 to 3 cents/kWh.

An example of the value of photovoltaic generation is presented by applying supply curve information to data from a PV installation near Philadelphia. Because photovoltaics generate a large fraction of their energy during summer on-peak periods, PV generation had a market price of 3.2 cents/kWh, approximately 33% more than baseload power for the 12 months ending September, 2000. The value of load reduction for PV generation was 10.0 cents/kWh, 58% above the value of load reduction for baseload generation (6.5 cents/kWh)

## Estimating Cost Curves for the PJM Market

The PJM market is a power pool with prices established in a relatively large number of zones. While recognizing that zonal differences may be important in setting short-term prices in some regions, the average PJM price was used to obtain a generalized regional relationship between price and load. Only energy prices were included in this analysis, because of the complexity of managing data for ancillary services, and the relatively small increment of price represented by ancillary services. A similar investigation of

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<sup>1</sup> Prices were considerably higher in 1999 due largely to higher loads.

California prices found that the cost of ancillary services (reserves and regulation) was only 1-3% of the energy cost at low load levels and 3-8% of the energy cost for loads during the summer 2000 peak. (Marcus and Ruzovan, 2000)

Regression equations, which related observed prices to demand were used to estimate cost curves. A typical “hockey stick” relationship was observed, with relatively low prices at low load levels. Prices rise slowly as load increases at low load levels and then rise more rapidly as loads reached peak levels.

On the PJM system, a “family” of curves was observed, with lower prices for the same load level in the peak winter and summer months than in March through May and October and November (when maintenance levels were high), and slightly higher prices on weekends than on weekdays (reflecting that fewer units were running). Several curves had to be fit at different load levels, because the PJM system was relatively insensitive to gas prices at low load levels but became sensitive to gas prices above 30,000 MW (in approximately 40% of hours).

Appendix A provides details on the development of energy cost curves for PJM.

## **Value of Load Reduction (Energy Conservation and Distributed Generation)**

### **Introduction**

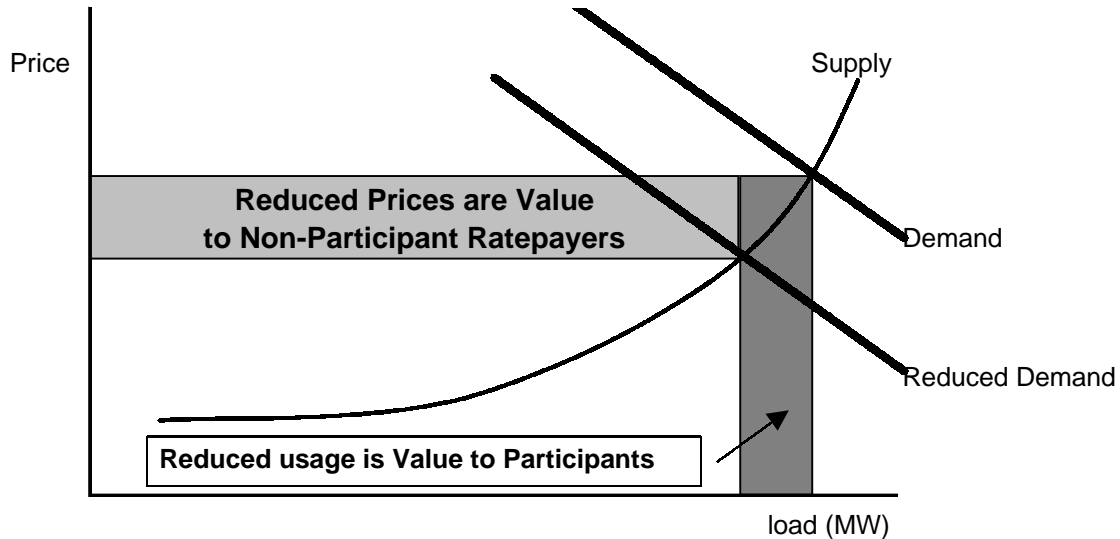
In addition to the direct cost of energy prices, load reduction, energy conservation, and distributed generation all have a significant value in reducing the overall system cost of electricity.

In the old world, in a given hour the marginal cost of energy of a bundled utility was the price of the last most expensive unit of the utility’s generation. But the cost was only incurred for that last unit. Thus, the marginal cost was the value of demand reduction, because the last unit’s generation was avoided.

In the new world of power pools (in places such as PJM, New York, New England, California, and Alberta) the price for all units of energy traded through the pool is set on an hourly basis by the market-clearing bid price for the last unit (of generation or load reduction) bid in to serve demand. As demand rises, the total revenue received by all generators rises. Thus the value of demand reduction from the perspective of ratepayers is not just the market price (bid price of the last unit). It is the market price plus the increase in the bid price multiplied by all other generators except the last unit.

As demand rises, particularly in peak periods, the price of energy rises relatively rapidly. If demand can be reduced, for example due to the installation of more efficient appliances, the price will tend to fall as demand falls, benefiting not only the customer whose demand is reduced but all other customers who receive the lower prices of spot market energy. Figure 1 shows the effect graphically for a given hour.

**Figure 1: Market Price and Value of Load Reduction**



The reduction in usage multiplied by the original market price is a benefit to the customer(s) reducing load. The reduced price multiplied by the usage after the reduction benefits all other loads. The sum of these two shaded blocks is the total value of load reduction. Dividing the sum of the blocks by the MWh of load savings gives a value in \$/MWh that is higher than the market price.

The argument made here is not a new one. In the context of the world oil market, several studies in the past 20 years have identified the significant monetary value to consumers of demand reductions that can cause price reductions.<sup>2</sup>

This effect was first pointed out quantitatively by Rich Ferguson of the Center for Energy Efficiency and Renewable Technologies (Ferguson, 1999). This issue was further analyzed, using data through mid-1999, by Marcus (2000) in testimony opposing fixed customer charges in a San Diego Gas and Electric Company rate design case.

The California ISO recognizes that the lack of demand responsiveness by customers has an impact on price performance in the California market, (Wojak et al, 2000) although it is largely considering real-time responses rather than investments in efficiency or distributed generation to reduce demand at all load levels.

### **How Hedging of Power Prices and Long-Term Generation Construction Affect the Results**

To review this issue further, we must consider the impact of hedging the short-term market price. There are two different kinds of hedges – physical hedges and contractual hedges. Under a physical hedge, a utility may own a plant which delivers power under a price based generally on a cost of service approach and gives the preponderance of excess

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<sup>2</sup> See, for example Broadman and Hogan, 1988, Stobaugh and Yergin, 1980, pp. 57-60.

revenue earned in the market to ratepayers, or a third party sells power at levels that are at least in part tied to the cost of the generating plant. For example, in California, hydroelectric power is likely to end up being a physical hedge.

Contractual hedges, by contrast, are market-based prices established by the market, and locked in for a varying period of time from a week to several years. Theoretically, these hedges are based on expectations of future market prices plus an insurance premium. Economic theory suggests that the pricing of contractual hedges are based on all information available to the participants in those hedges regarding future market trends. If a credible program of efficiency, load shifting, and DG is undertaken, backed by physical investments, market participants should take those programs into account.

As a result, we now conclude that the value of demand reduction in reducing prices applies to contractual hedges but not to physical hedges.

In addition, one must examine longer term considerations. In the longer term, the price-reducing impact of demand-reduction may be less than in the short term, because price reduction induced by efficiency or DG investments may reduce the amount of generating plant that is built, which could create some countervailing upward price pressure. As a result, the higher value of demand reduction that is clearly present in the short term – particularly under conditions of short supply – is likely to weaken over time.<sup>3</sup>

As a result, we analyze two cases – an “unhedged” case where the price reduction applies to 100% of generation. This is a short-term polar case assuming that no generation is provided on cost-based terms and there is no erosion of the effect as efficiency displaces new construction. The second case assumes that price reduction applies to 50% of generation, taking into account physical hedges and long-run reductions in the magnitude of the effect.

### **Example of Calculation Method**

An example of the method used to calculate market prices and the value of load reduction is shown below. These types of calculations, from the supply-demand equation, are used throughout the analysis.

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<sup>3</sup> Eric Hirst also suggested (in a personal communication) that changes in unit commitment caused by load reduction may affect prices, particularly at lower load levels, causing some erosion of the effect. There is no good way to test such a hypothesis with the data at hand. In an hour-ahead market, such impacts are likely to be larger than in a day-ahead market.

An example of the method used to calculate market prices and the value of load reduction is shown below. These types of calculations, from the supply-demand equation, are used throughout the analysis.

**Table 1: Calculation Example**

	MW	Price *	Pool Revenue
Load	40000	45.5364	1821454
Reduced load	39000	41.2771	1609808
Difference	1000		211646
Value of load reduction unhedged			211.646
Value of load reduction 50% hedge **			128.591
* Summer/winter weekday, \$4.00/MMBtu gas			
** 50% of VLR unhedged + 50% of original market price			

With a 1000 MW load reduction, the market price falls from 45.53/MWh to \$41.28/MWh, generating a reduction of \$211,646 in the hour if all costs were exposed to the pool price, or a value of load reduction of over 21 cents/kWh. With 50% of generation hedged, the value of load reduction is slightly less than 13 cents/kWh, 282% of the market price.

### **Overall Results**

Figure 2 compares the value per kWh of a (1000 MW) reduction in energy use from all load levels to the energy price, with no hedging, and with 50% hedging.<sup>4</sup> It shows that, including the impact on the market price, even with 50% physical hedging the value of load reduction is at least 170% of the value of energy at all loads. Above 30,000 MW, both prices and the value of conserved energy rise rapidly, but the value of load reduction rises faster. The value of load reduction rises from 217% to 294% of the market price of energy from 31,000 to 40,000 MW and then rose faster to reach 3-1/2 times the market price at 45,000 MW and 8 times the market price at 50,000 MW. Without hedging, the figures are even higher.

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<sup>4</sup> The gap at 30,000 MW is shown on this figure because of the shift between two separate cost curves.

Figure 2

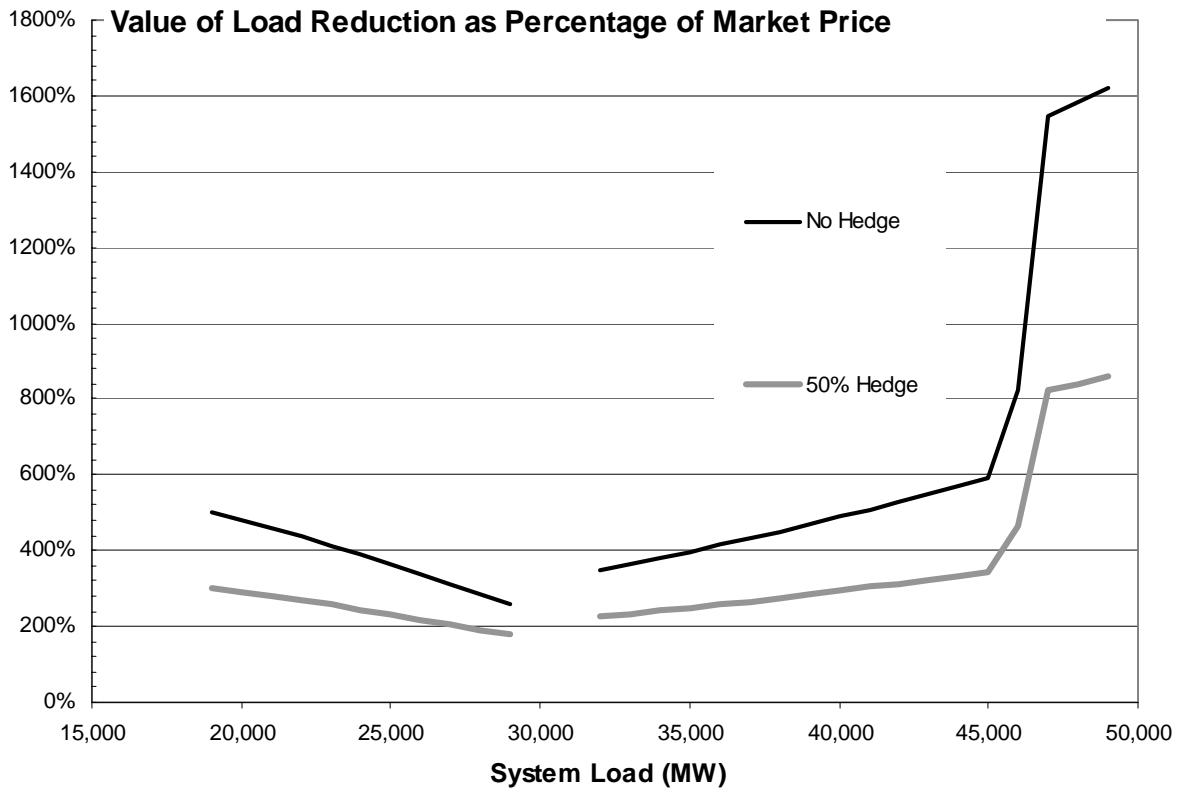


Figure 3 compares the unhedged and 50% hedged value of load reduction to the market price (assuming gas at \$4/MMBtu). At the lowest load levels, the unhedged value of load reduction is about \$20-\$25/MWh, but it rises rapidly to reach \$40/MWh at 24,000 MW (with market prices of \$10-\$13/MWh), \$70 at 32,000 MW, \$100/MWh at 35,000 MW, \$200/MWh at 40,000 MW, and in excess of \$1000/MWh at about 45,000 MW.<sup>5</sup> With a 50% hedge, the values are lower, but are still in the \$25-\$35 range between 20,000 and 30,000 MW, \$60 at 35,000 MW, \$100 at 39,000 MW, and \$200 at 44,000 MW, spiking to more than \$1000 at the top of the peak.

<sup>5</sup> The value of load reduction below 40,000 MW is higher than reported figures in April and May.

Figure 3

**Value of Load Reduction: No Hedging versus 50% Hedged**  
 Weekday, Winter and Summer

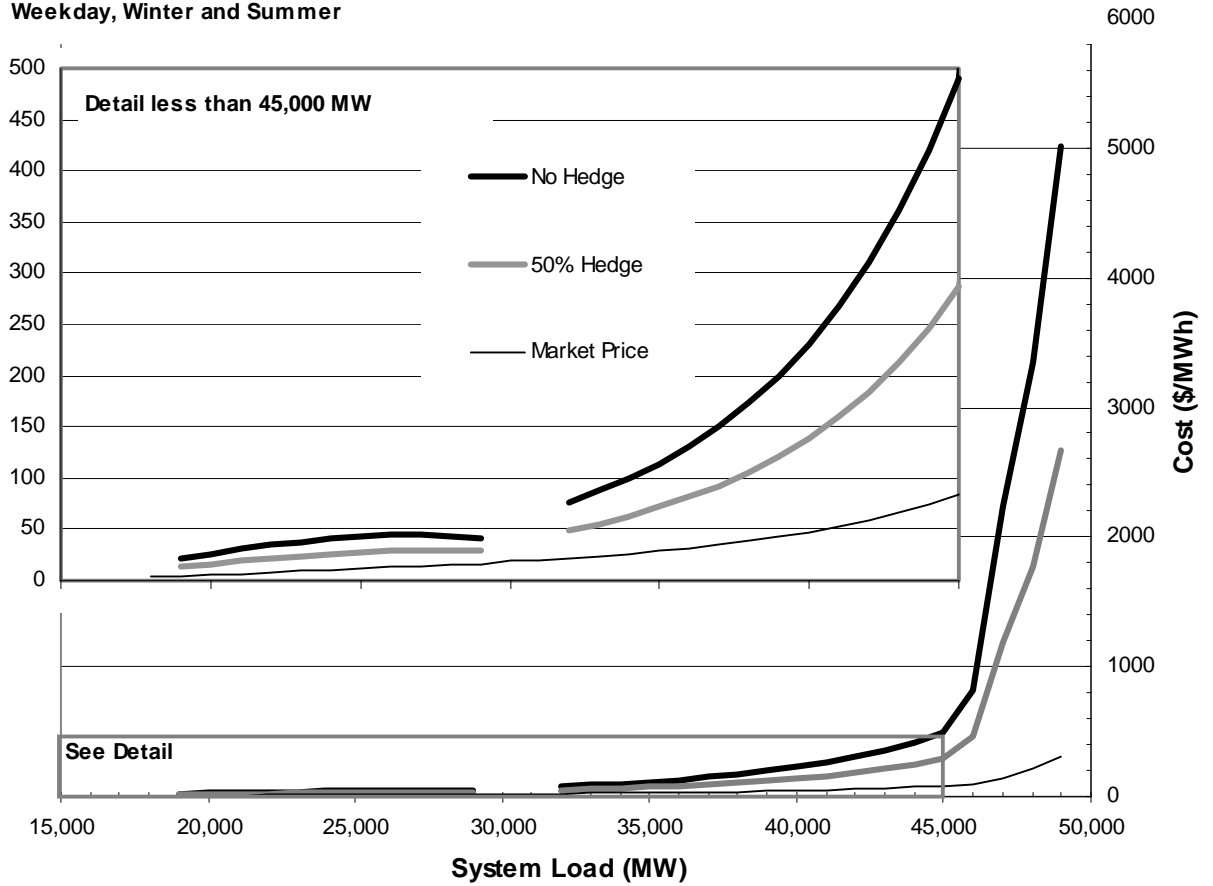


Table 2 below extracts similar information for all four cases, with no hedge and a 40% physical hedge.



## Time of Use Analysis

A comparison of the actual market prices, the prices predicted by the supply curve model, and the value of energy reduction was also developed by time-of-use period for a 12-month period from October, 1999 through September 2000.<sup>6</sup> (Table 3)

**Table 3**

### **Time of Use Analysis of Market Price and Value of Load Reduction**

	Actual Market Price	Market Price Calculated from Regression	Value of load reduction 50% hedged	Load Reduction as % of market price
<b><u>Summer (June-September)</u></b>				
On-Peak (weekday 12pm-6pm)	4.90	5.28	24.51	464%
Mid-Peak (Mon thru Sat 6am-10pm except on-peak)	3.15	2.97	8.17	275%
Off-Peak (10pm-6am plus Sunday)	1.71	1.64	3.86	235%
Season total	2.83	2.79	9.13	327%
<b><u>Other (All Other Months)</u></b>				
Mid-Peak (Mon thru Sat 6am-10pm)	2.85	2.76	6.30	228%
Off-Peak (10pm-6am plus Sunday)	1.55	1.56	3.59	230%
Season total	2.27	2.23	5.09	228%
<b><u>Annual total</u></b>	2.46	2.43	6.51	268%

This table shows that:

1. With the exception of the very high prices in the summer peak of 1999, the model generally predicted seasonal costs within 2%. No time period was off by more than 6%.<sup>7</sup>
2. The value of load reduction during summer peak hours is almost 25 cents per kWh – 4.6 times the market price of power calculated from the regression equation. During summer mid-peak hours, the value is 8.2 cents/kWh. Due

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<sup>6</sup> To reflect current conditions, a gas price of \$4/MMBtu was used in the regression to develop the market price by time of use. It should be noted that similar calculations using the 1999 load curve, with higher loads, are considerably higher, particularly on-peak. Thus, if loads in the summer of 2000 are recognized to be lower than average, its prices are also significantly lower than could be expected in an average year.

<sup>7</sup> The model did not track the very high prices in the summer of 1999 well, under predicting costs in the very highest peak hours that drove up PJM prices, suggesting that other factors such as generation shortages or market power may have had an influence in those hours. PJM suggests that generating outages were higher at the time of the 1999 peak than the 7.5% projected on a planning basis for 2000. (PJM, 2000a, 2000b).

to warmer temperatures in 1999, the value of load reduction in the summer of 1999 was higher, reaching 46 cents/kWh on-peak and 14 cents/kWh mid-peak.

3. During off-peak and other mid-peak hours, the value of load reduction is 3.5 to 6 cents/kWh – 228% to 235% of the market price.

### **Case Study: Analysis of Photovoltaic Generation**

A specific analysis of photovoltaic generation was conducted as an example of how the value of load reduction may affect planning for peak-oriented investments that reduce customer loads. A qualitative analysis (JBS Energy, 1996), integrated PV generation with system and class load curves for a California utility to show the benefits of PV generation.

The actual output curve for a PV generator in Plymouth Meeting, PA (near Philadelphia) was used<sup>8</sup>. The PV has a nameplate AC rating of 53 kW, but empirically has experienced a limit on hourly output of approximately 40 kW (both actual and modeled). It produced 47,000 kWh (for a capacity factor of 14% based on 40 kW maximum output) in 8328 hours since mid-October, 1999.<sup>9</sup>

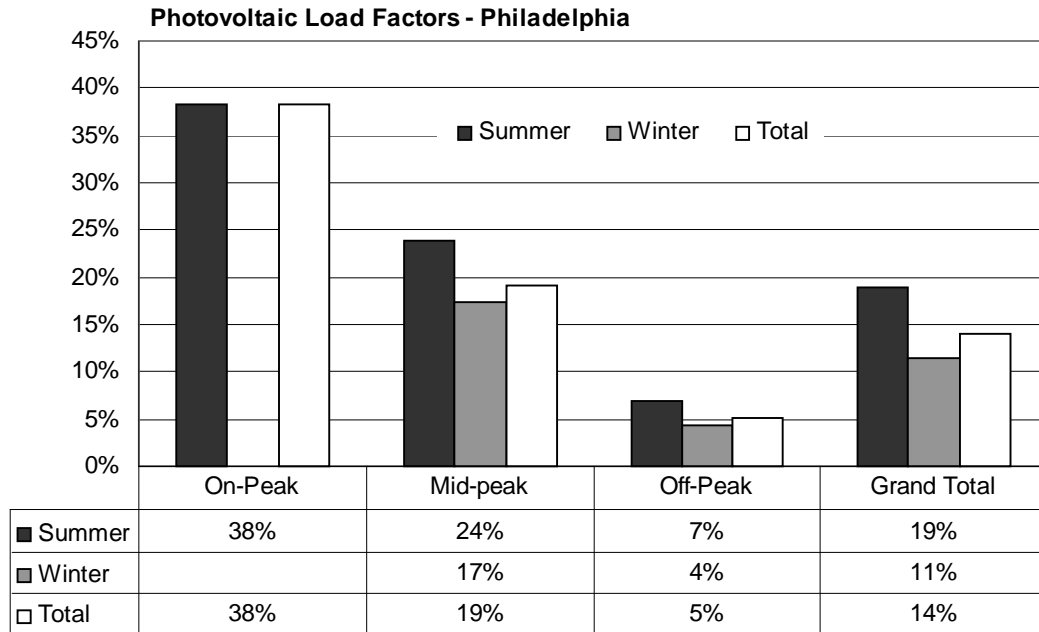
The load factor varies significantly by season and time of use, as shown in Figure 4.

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<sup>8</sup> Data was obtained from the Utility Photovoltaic Group's TEAM-UP PV system performance database available on the Internet at <http://www.ttcorp.com/upvg/sindex.htm>.

<sup>9</sup> As actual output was used, and this is a relatively new facility, the impact of start-up on performance cannot be ruled out, and actual performance in excess of 14% may be expected.

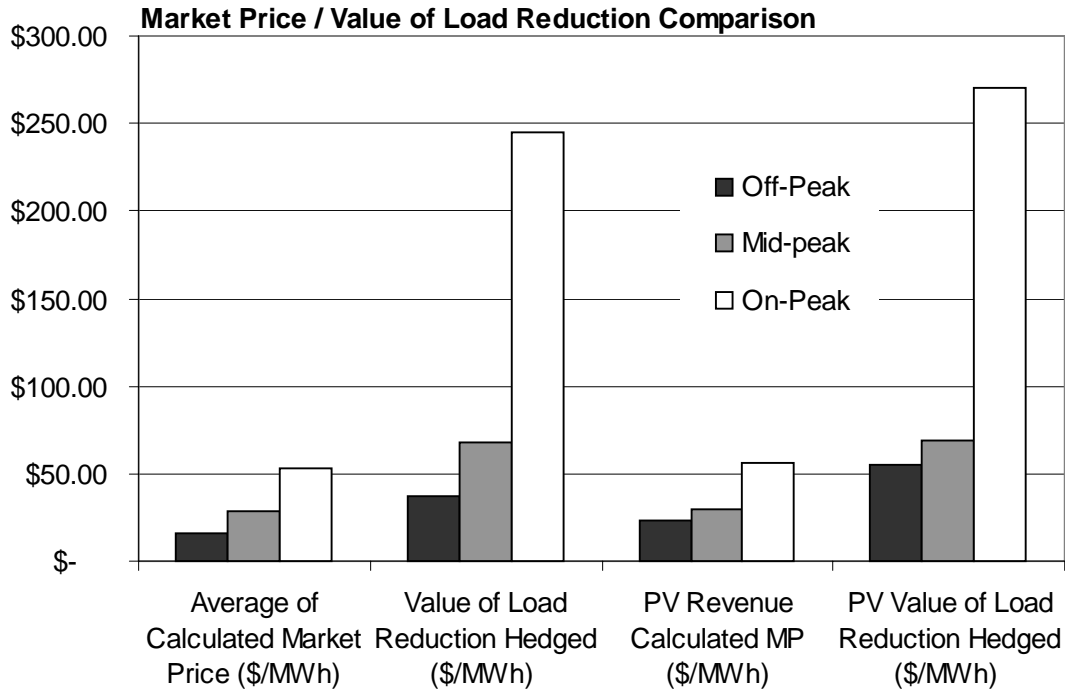
**Figure 4**



Capacity factors reach 38% in the summer on-peak, but are only 5% year round in the off peak hours (largely Sunday daytime output). During mid-peak hours (6am-10pm Monday-Saturday except summer peak), the PV capacity factor is 24% in the summer and 17% in the winter).

Because its output is weighted toward daytime hours, a PV has both a higher market price and a higher value of load reduction than a more baseload supply reduction (e.g., a DSM program to retrofit exit signs or traffic lights, or improve residential refrigerator efficiency), as shown in Figure 5 and Table 4.

**Figure 5: Comparison of Market Prices and Value of Load Reduction for Baseload Application and Plymouth Meeting Photovoltaic**



**Table 4**

**Time of Use Analysis of Market Price and Value of Load Reduction: Photovoltaic Generation Pattern**

	Actual Market Price	Market Price Calculated from Regression	Value of load reduction 50% hedged	Load Reduction as % of market price
<b>Summer (June-September)</b>				
On-Peak (weekday 12pm-6pm)	5.02	5.64	27.07	480%
Mid-Peak (Mon thru Sat 6am-10pm except on-peak)	3.28	3.04	8.10	266%
Off-Peak (10pm-6am plus Sunday)	2.69	2.55	6.38	250%
Season total	3.80	3.88	14.51	374%
<b>Other (All Other Months)</b>				
Mid-Peak (Mon thru Sat 6am-10pm)	2.91	2.86	6.27	219%
Off-Peak (10pm-6am plus Sunday)	1.95	2.07	4.68	226%
Season total	2.75	2.72	6.01	221%
<b>Annual total</b>	3.25	3.27	10.02	306%

PV generation is worth 32% more than baseload generation (3.25 cents/kWh vs. 2.46 cents/kWh) because its generation load profile is more oriented toward the summer

daytime period.<sup>10</sup> The costs in the on-peak and mid-peak periods are only slightly higher than baseload power, but the off-peak value is much higher (because it is largely made up of Sunday daytime generation and includes almost no loads between 10pm and 6am), and the amount of off-peak generation is low.

Because the value of load reduction is higher during summer peak periods when the PV is producing power, it exceeds 10 cents/kWh in the year 2000 period, 306% of the market price of energy and 58% above the value of load reduction associated with baseload generation.

It should be noted that with the much higher loads and market prices experienced in 1999, the value of PV generation would have been considerably higher – likely in the range of 15 cents per kWh. However, the value of PV generation could not be analyzed using real facility data because the Plymouth Meeting PV data only began to be collected in October, 1999.

### **Policy Implications**

This information runs counter to conventional wisdom. Energy efficiency and distributed generation is not necessarily a breeder of rate increases. At all load levels, the potential for rate increases is greatly mitigated by the reduced commodity prices for everyone that result from reducing load. Conservation in peak hours, by all customers, but most particularly by load profiled residential and commercial customers, can provide major rate savings.

Energy efficiency is of critical importance now, but it is not just a way to get through a crunch of tight supply and high gas prices. Even in the “good-old-days” scenario of \$2.44 gas and with a 50% physical hedge, energy efficiency would still be worth at least 2 cents per kWh in the deepest off-peak, 3-4 cents per kWh in typical off-peak periods, 4-6 cents per kWh in mid-peak periods, and 6-12 cents from 35,000-40,000 MW, rising drastically to 25 cents/kWh at 45,000 MW and several dollars per kWh at peak.

The analysis shown above does not mean that all of the numbers calculated from this particular cost curve will remain correct if the cost curve shifts again (e.g., because of the addition of new generators). However, the analysis demonstrates the reasonableness of the concept– **that demand reduction has a value to society on the order of more than twice the market price of power during most hours of the year, and that it rises to being three to eight times as valuable as the (increased) market price during the 10% of hours closest to the peak.**

The shape of the curve depends on the specifics of supply, demand, and market power of the system. However, the fact that conservation is worth more than the market price is structural – based on the workings of the new market.

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<sup>10</sup> With the higher loads experienced in 1999, the value of PV generation would increase even more.

The lesson to be learned from this information is not necessarily to pursue all energy efficiency and distributed generation options that are less than the value of load reduction calculated above, or to assume that calculations such as those presented in this report are precise estimates with no margin of error. Rather, it is important to use the information to gain several key qualitative and policy insights:

1. That decision-makers should be less concerned about rate impacts of spending money on load reduction, such as investments in energy efficiency and distributed generation, because rate increases will be mitigated or even reversed (with savings achieved during peak periods) by the price reductions created by such investments.
2. To focus more spending on peak conservation and load shifting where the impact of price reduction is stronger, while continuing to recognize that the effect is present, though less pronounced, off-peak. This information provides a strong impetus for programs such as replacing inefficient window air conditioners and air conditioner and water heater cycling, as well as ratcheting up Federal energy efficiency standards for air conditioners.
3. To encourage large customers to become more price-responsive because of system-wide benefits generated from such price responses.

At the same time, the data clearly demonstrate that the market price by itself does not represent the full value of energy conservation, distributed generation, and load reduction. The contention of Shimon Awerbuch (2000) and economists at the California Energy Commission [for example, Goeke (1996)] that society would be better off with price signals such as customer charges that encourage purchase of more kilowatt-hours and fewer energy-saving devices ignores this significant financial externality.

## **Conclusion**

The value of load reduction from the perspective of ratepayers (in reducing the prices paid by everyone) is at least twice as great as the market prices themselves, and it rises dramatically as load increases.

It is clearly in the best interest of society to spend money and send price signals beyond the market price to encourage energy efficiency and load shifting, particularly during the summer peak. Distributed photovoltaic generation, with its relatively strong correlation with peak loads, could be particularly important in this regard. This finding that conservation not only benefits the conserver but everyone else should become the cornerstone of a new public goods imperative and the associated rate design policy.

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## **Appendix A Development of PJM Supply Curves**

A supply curve was fit piecewise using three separate regressions for PJM using data for the period from April 1, 1999<sup>11</sup> to July 28, 2000. This type of analysis using separate regressions is required because:

- (1) PJM prices are almost insensitive to gas/oil prices if load is either very low or very high, but are more sensitive to gas/oil prices in an intermediate range (i.e., from 30,000 to 45,000 MW). Gas/oil units are the marginal units at high load levels, but not at low load levels. A single equation will not capture this phenomenon.
- (2) At the highest load levels, PJM prices increase dramatically near the system peak, but are not as sensitive to gas, being more heavily based on shortage values.

As a result of these two phenomena, a single equation cannot be fit. A single equation will overestimate low-end prices and underestimate peak prices, while at the same time underestimating the gas sensitivity of prices during normal intermediate and peak operation.

Three separate curves were therefore fit, including limited amounts of overlapping data:

- 1) Load below 30,000 MW (6390 data points or 54.9% of hours)
- 2) Load from 30,000 to 45,000 MW<sup>12</sup> (5040 data points or 43.3% of hours)
- 3) Load above 43,000 MW (387 data points including 289 over 45,000 MW or 3.3% of hours above 43,000 MW and 1.8% above 45,000 MW)<sup>13</sup>

All equations were fit to a logarithmic form and were run using a Prais-Winsten transformation to correct for autocorrelation of residuals.<sup>14</sup> The results were:

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<sup>11</sup> Prior to April, 1999, there were restrictions on bidding. (Van Vactor, 2000) Our regression analysis showed that prices were higher prior to April, 1999, at load levels below 43,000 MW.

<sup>12</sup> Tests were run in 3000 MW increments to determine where gas price sensitivity first appears. The 30,000-33,000 MW load level was the first appearance of significant sensitivity to gas prices.

<sup>13</sup> Because the period before and after April 1999 had an insignificant impact on prices in the high load hours, and there were relatively few data points in this curve, the entire period was used to estimate this curve.

<sup>14</sup> Autocorrelation of residuals is a significant issue when using time-series data because factors which cause the price to be unusually high or low in a given hour (e.g., unusually small or large amounts of generation available) tend to persist over a number of hours or days.

### **Below 30,000 MW**

$$\begin{aligned} \ln(\text{price}) = & -93.2762 + 10.1958 * \ln(\text{load}) - 0.00030 * \text{load} \\ & (11.43) \quad (11.40) \quad (8.38) \\ & + 0.1212 * (\text{dummy 1} = \text{weekend } 0 = \text{weekday}) + 0.23999 * (\text{dummy 1} = \text{March } 0 = \text{other}) \\ & (5.71) \quad (4.81) \\ & + 0.46173 * (\text{dummy 1} = \text{Apr. or May } 0 = \text{other}) + 0.10429 * (\text{dummy 1} = \text{Oct. or Nov. } 0 = \text{other}) \\ & (15.78) \quad (2.83) \end{aligned}$$

Rho = 0.6615   Adjusted R-squared = 0.210

### **30,000 to 45,000 MW**

$$\begin{aligned} \ln(\text{price}) = & 1.3490 + 0.13288 * (\text{LOAD}/10000)^2 + 0.27408 * \text{LN}(\text{SPOTGAS})^{15} \\ & (20.97) \quad (38.94) \quad (5.77) \\ & + 0.07282 * \text{WEEKEND} + 0.37291 * \text{MARCH} + 0.52463 * \text{APRMAY} + 0.29763 * \text{OCTNOV} \\ & (2.99) \quad (7.99) \quad (15.98) \quad (7.52) \end{aligned}$$

Rho = 0.5771   Adjusted R-squared = 0.246

### **Over 43,000 MW**

$$\begin{aligned} \ln(\text{price}) = & 1.87111 + 0.11604 * (\text{LOAD}/10000)^2 \\ & (1.71) \quad (2.09) \\ & + 0.000269 * (\text{Load} - 45000 \text{ MW, zero if negative}) \\ & (3.81) \end{aligned}$$

Rho = 0.7673   Adjusted R-squared = 0.185

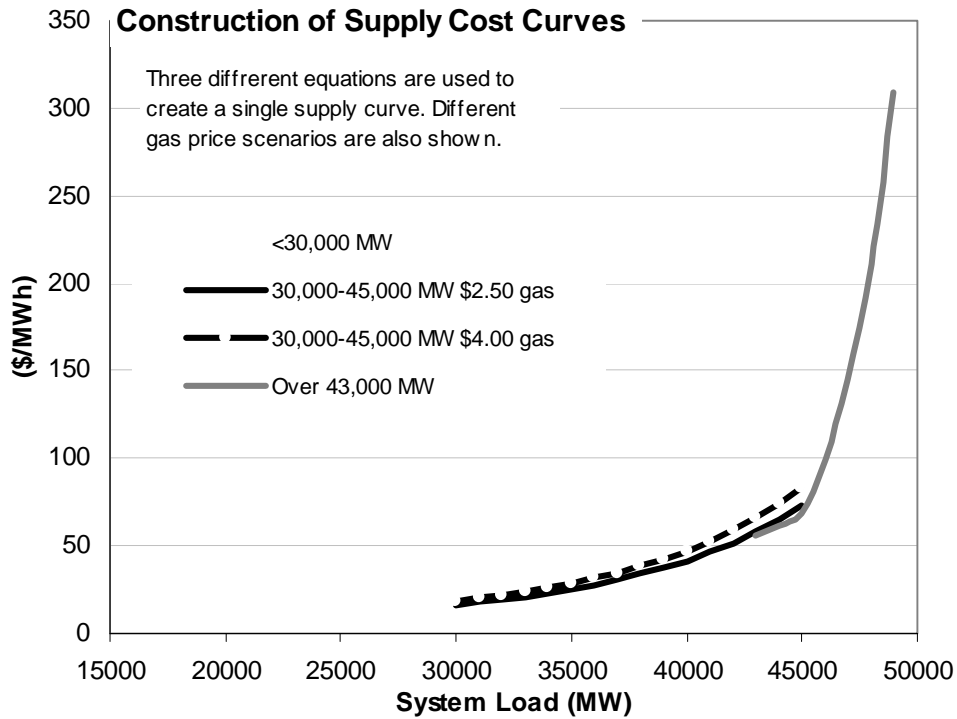
### **Analysis of Regression Equations**

The three equations give relatively straightforward results. Figure A-1 shows an example of how the three equations fit together at average (\$2.445/MMBtu) gas prices experienced over the period and higher (\$4.00) gas prices consistent with current conditions for winter and summer weekdays.

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<sup>15</sup> Measured at Henry Hub.

Figure A-1



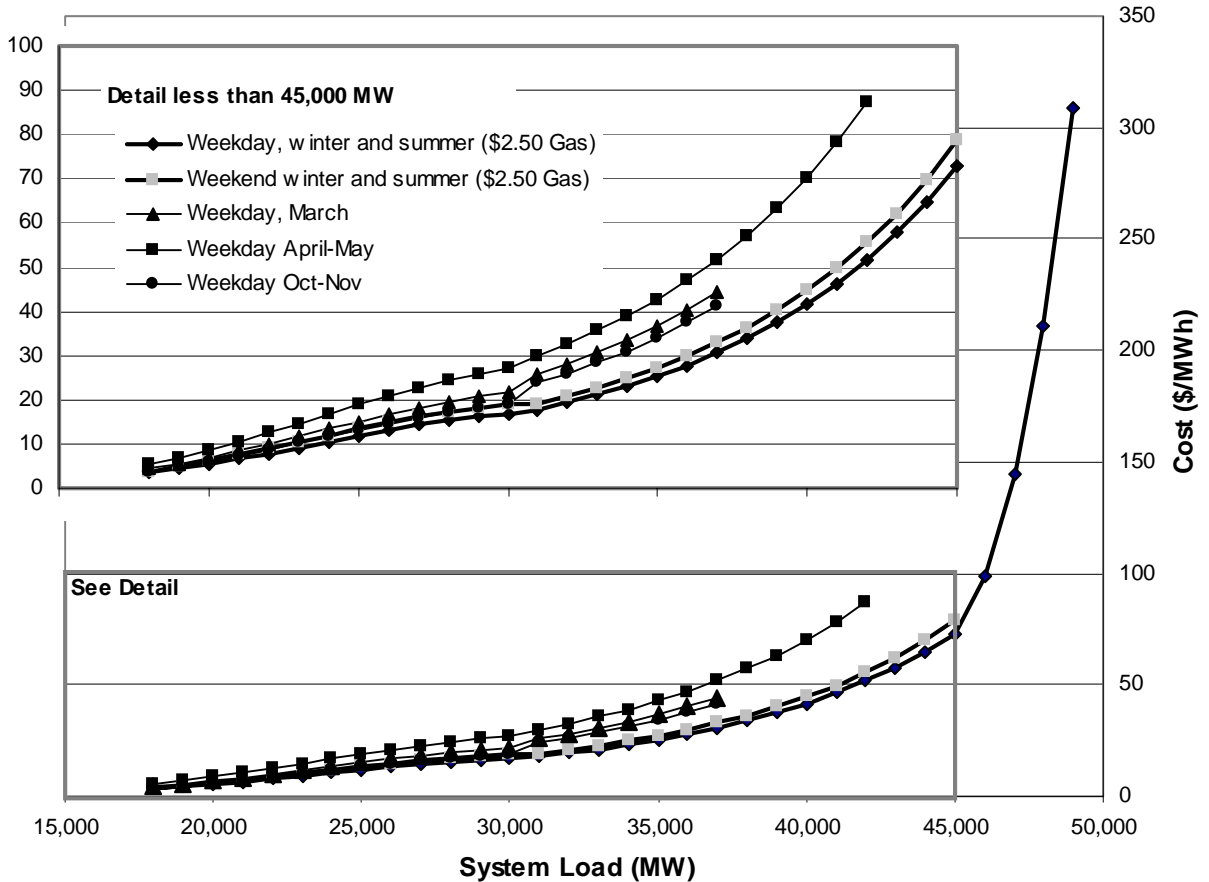
Controlling for load levels and gas prices, energy market prices were higher in the off-peak months of March through May and October and November, reflecting that more generation is on maintenance in those months. Similarly, energy prices were higher on weekends after controlling for loads and gas prices, reflecting that generators which are run on weekdays to meet loads may be taken off line on weekends for economic reasons.<sup>16</sup> Figure A-2 illustrates this phenomenon.

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<sup>16</sup> The weekend and seasonal variables were deleted in the equation above 43,000 MW, because there were no hours with load over 38,000 MW in March, October and November, and very few hours in April, May, and on weekends over 43,000 MW.

Figure A-2

Comparison of Supply Curves



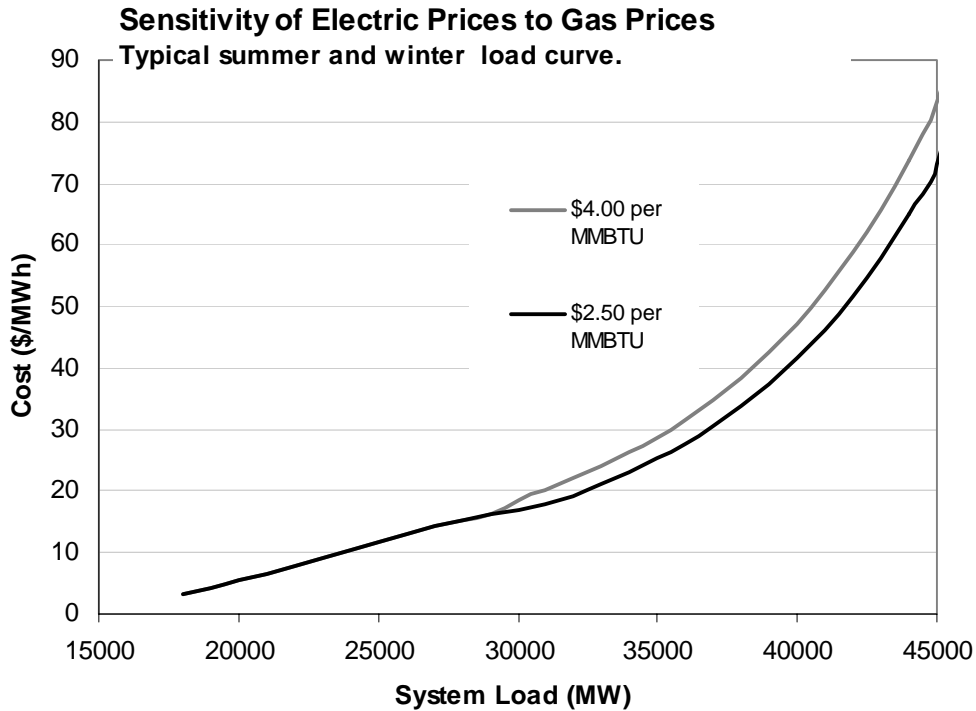
In all three equations, prices increased relatively rapidly as load rises.

In over half of the hours (up to 30,000 MW), prices are largely based on coal generation, with costs of less than \$22/MWh (except in April and May). Above 30,000 MW, some gas and oil-fired generation comes into the mix. At the average level of gas prices over the time period (\$2.445/MMBtu), prices rise rapidly, reaching levels equal to the cost of gas-fired steam generation in summer and winter months at about 34,000 MW (at lower load levels during off-peak months). Prices rise to \$30/MWh at 37,000 MW, \$40 at 40,000 MW, and \$70 at 45,000 MW. In the few hours with loads above 45,000 MW, prices spike to \$450/MWh near the top of the peak at 50,000 MW.

The elasticity of price with respect to gas price for loads over 30,000 MW is 0.27, meaning that for every 10% increase in gas prices, energy prices at loads greater than 30,000 MW rise by 2.7%. Review of data in 3000 MW increments suggest that the elasticity of electricity prices with respect to gas prices is not constant but increases between 30,000 and 40,000 MW, as would be expected as more gas- and oil-fired generation enters the mix, but the statistical estimation of this phenomenon is not straightforward. At current prices in the vicinity of \$4/MMBtu, prices in the 30,000-

45,000 MW range average 17% above prices consistent with average (\$2.445/MMBtu) gas prices. Figure A-3 shows the sensitivity of electric prices to gas prices for a typical (summer and winter) load curve.

Figure A-3



Equations showed somewhat weak R-squared results, fitting 20-25% of the variation, for several reasons. First, explicit generation supply variables were not included. Second, these are hour-ahead markets, where prices are often quite volatile, related to constraints such as unit commitment and ramping.<sup>17</sup> In addition, it was determined empirically that a somewhat higher R-squared could be derived by including a variable for the previous day's peak load (which reflects that more generating units are committed to run for a higher peak, depressing off-peak prices), but the interpretation of such a variable in a supply/cost curve analysis would be difficult.

<sup>17</sup> Analysis of California's markets showed more volatility and higher standard errors in regressions estimating the hourly ISO imbalance market than the day-ahead PX market. (Marcus and Ruszovan, 2000)