Dynamic Pricing Tariffs for DTE's Residential Electricity Customers

By

Arie Jongejan, Brian Katzman, Thomas Leahy, and Mark Michelin

A project submitted
in partial fulfillment of the requirements for the degree of
Master of Science
(Natural Resources and Environment)
at the University of Michigan
April 2010

Faculty advisor:
Professor Greg Keoleian

Abstract

Despite temporal changes in wholesale electricity prices, retail prices are typically constant throughout the day. To address this economic inefficiency, Detroit Edison, a subsidiary of DTE Energy (DTE), can introduce residential dynamic pricing rates to incent customers to shift load away from peak periods, at which time wholesale electricity prices are high. This paper estimates the financial and environmental impacts of implementing dynamic electricity pricing rates for residential customers within the Midwest Independent System Operator (MISO). Based on these estimates, we recommend that DTE pilot specific residential dynamic pricing rates, all of which may be suitable for wide-scale deployment.

We researched existing pricing programs that have been piloted throughout the country to determine which options present the most potential to reduce or shift peak load. In addition, we obtained cost estimates for enabling technology to be used in conjunction with these tariffs. We then constructed a dispatch model which simulates the MISO electricity market by using electricity supply and demand forecasts for 2010-2030. Applying residential peak load reduction and shifting estimates from previous pilots to the dispatch model, we calculate avoided capacity savings, avoided energy savings, and emissions impacts for various dynamic pricing programs. Specifically, we analyzed a Time of Use (TOU) tariff and TOU/Critical Peak Price tariff with and without enabling technology (smart thermostat and in-home display), as well as a TOU/Peak-time Rebate tariff. We investigate these tariffs using peak and critical-peak period window lengths ranging from four to eight hours.

There were three central results. First, deployment of demand response programs to a subset of residential customers with a four-hour peak window results in financial outcomes ranging from a net loss of $350 million to a net gain of $400 million. Second, enabling technology increases peak load reduction, but technology costs may exceed the savings of the increased load reduction. Third, the length of the peak window is an important driver of economic benefits; increasing the window length may enhance net economic benefits.

Acknowledgments

We would like to thank the many individuals and groups that helped make this research possible. Our faculty advisor, Greg Keoleian guided us from start to finish and was an integral part of all aspects of the project. Doug Ziemnick at DTE acted as a mentor and guide and provided countless hours to help us produce this research. In addition, Doug provided us with key information, data, and contacts at both DTE and its vendors.

A fellow MS candidate at the School of Natural Resources (SNRE), Jason McDonald, provided us with important load data and helped us as we developed our dispatch model. Former SNRE faculty member, Duncan Callaway, and former Ford School faculty member, Meredith Fowlie, provided us with early feedback on our pricing research and helped us to define the project scope. Professor Tom Lyon provided guidance on our modeling efforts. George Mundorf at DTE reviewed our dispatch model and helped us to understand which results would be of particular interest to DTE. Dr. Ahmad Faruqui and Ryan Hledik at the Brattle Group provided us expert tutelage as we waded through in-depth elasticity measurements. Dr. Bernard Neenan from the Electric Power Research Institute (EPRI) provided us further guidance on understanding own price and substitution elasticity mechanics.

We are grateful to the School of Natural Resources and Environment and the Erb Institute for providing the funding to make this research possible. Finally, we would like to thank our friends and families for supporting our efforts and sharing in our excitement throughout this process.

Contents

1 Executive Summary

Introduction

The goal of this Master's Project is to recommend pricing pilots that our client, Detroit Edison, a subsidiary of DTE Energy (DTE), may implement with residential customers using Advance Metering Infrastructure (AMI). The ultimate goal is for DTE to collect data about how their customers respond to electricity prices to identify the most promising mechanisms suitable for wide-scale deployment.

Michigan is part of the Midwest Independent System Operator (MISO), a partially deregulated market in which wholesale electricity prices are determined via an auction process. Despite fluctuations in the cost of the electricity, the retail price is fixed and does not reflect real-time changes in wholesale prices. The current absence of significant price signals means that there may be an opportunity for DTE to implement market-based mechanisms to incentivize customers to shift load away from peak periods during which load is particularly expensive to service.

Methods

To evaluate the ways in which DTE could send price signals to its customers, we researched existing pricing programs that have been piloted or implemented throughout the country to determine which options present the greatest potential to reduce or shift peak load. Specifically, we evaluated Critical Peak Pricing (CPP), Time of Use Pricing (TOU), combined CPP/TOU Pricing, Real Time Pricing (RTP), and Peak-Time Rebate (PTR) programs. Each of these tariff structures were analyzed to determine the expected demand shift and corresponding economic benefits associated with implementing that particular program. Further, we identified common trends across tariff structures that appeared to increase net economic benefit. We found that TOU and CPP tariffs produced the greatest reduction in peak demand and were often bolstered by enabling technology, such as a smart thermostat, and excellent notification practices for peak event days. In addition, we looked outside of the electricity industry to determine other methods that companies have used to influence customer behavior, including point rewards programs and product giveaways; such programs would be new and innovative if applied in the electricity industry.

From this research, we presented eleven dynamic pricing programs to DTE that have the potential to incent customers to change their electricity consumption patterns. In consultation with DTE, we focused on three of these programs for in-depth analysis: TOU, TOU/CPP, and TOU/PTR. Each of these pricing structures was evaluated with and without the use of enabling technology. Narrowing the scope was necessary due to the intensive nature of the additional analysis, which consisted of constructing a dispatch model using estimates of electricity supply and demand from 2010-2030, estimating potential shifts and reductions in electricity load resulting from implementation of the pricing program, and running the model to calculate electricity load and price for each hour of each day over this twenty-year period. Load differences between a "business-as-usual" (BAU) scenario and the scenarios incorporating load shifts from dynamic pricing were used to calculate potential savings in both energy costs and avoided capacity costs resulting from consumers responding to dynamic pricing.

Results

Deployment of demand response programs to a subset of residential customers with a four-hour peak window will result in financial outcomes ranging from a net loss of $350 million for a TOU tariff with technology to a net gain of $400 million for a TOU/CPP tariff without enabling technology. $400 million represents a savings of less than 0.25% of total wholesale electricity costs and less than 1% of the residential portion of total wholesale electricity costs. TOU with enabling technology and TOU/CPP with enabling technology will result in the largest cost savings for DTE resulting in a cost reduction of approximately 0.30% of total wholesale electricity costs. However, if DTE must bear the cost of enabling technology, the cost savings of these programs are negative (i.e. a financial loss), changing to -0.14% of total energy costs. In this case, combined TOU/CPP and TOU/PTR programs offer the greatest cost savings to DTE. Therefore, DTE should strongly consider the option of incorporating the costs of enabling technology into its rate-base, or having customers contribute to the cost if it wishes to proceed with deployment of enabling technology.

These results are highly sensitive to the four-hour peak period used in many of the scenarios we modeled. In the deployment of a CPP/TOU with technology program, the hours adjacent to the 1:00 pm - 5:00 pm window become the peak hours once a sufficient number of customers are enrolled in demand-response pricing. Once this occurs, annual avoided capacity savings are very limited. In addition, avoided capacity savings will be diminished with further deployment of demand-response pricing because further demand-response pricing will further increase peak demand in the time periods adjacent to 1:00 pm – 5:00pm. As a result, there are diminishing avoided capacity gains with additional demand response penetration.

Financial returns to demand response pricing are also sensitive to the level of demand response. Modeling of various demand response scenarios (low, medium, and high) shows that the savings can range by more than $100M over the course of the twenty-year period evaluated. While predictions can be made using the price elasticities of DTE's customer base, wide variations of responses in previous studies indicate that this may be a challenging exercise.

Demand response tariffs may decrease emissions within MISO according to our model. This is likely due to the fact that for the majority of days in MISO, peak demand is actually served by coal generation facilities. This result is supported by FERC's classification of coal as a marginal fuel type, as well as baseload, within MISO. Thus shifting electricity consumption from peak to off-peak periods is actually shifting generation to a more efficient, relatively cleaner coal facility. This effect, coupled with pricing-induced conservation from demand response, appears to offset the increase in pollution from demand response on those days when peak load is served by natural gas generation.

The model was used to test how policy changes within MISO and the US might affect DTE's savings. We found that the savings from residential demand response programs are not sensitive to whether a renewable portfolio standard (RPS) within MISO shapes future generation capacity expansion. This outcome is explained by MISO's electricity demand. Rarely does demand approach the steep, expensive part of the supply curve within MISO and, as a result, there is little impact from shifting the supply curve to the right.

A carbon tax increases the financial impact of demand-response pricing. Because coal is typically the marginal plant in MISO, the carbon tax actually magnifies the financial gains from demand-response pricing by making the supply curve steeper. This increase in financial impact more than offsets the reduction in financial gain (due to the reduced spread in cost between coal and natural gas) when natural gas plants serve peak load.

Key Findings

1. **Combined TOU and CPP programs with or without enabling technology provide the greatest demand response in the residential electricity market.** A review of previous combined TOU and CPP programs found that they resulted in mean critical peak hour demand reductions of 36% when coupled with enabling technology and 17% without technology.
2. **Enabling technology substantially improves customer demand response but may not provide adequate economic returns to the utility if the utility bears the full cost of the technology**. Our modeling forecasted gross cost savings (i.e. ignoring enabling technology costs) of $572 million for deployment of a TOU tariff with enabling technology compared to savings of $105 million for a TOU tariff without technology using a four-hour peak period. Similarly, our modeling found cost savings of $633 million for deployment of a TOU/CPP tariff with enabling technology compared to savings of $399 million for a TOU/CPP tariff without technology using a four-hour peak period. However, we found the cost of deployment of enabling technology to be $925 million, which is greater than the additional cost savings captured by using enabling technologies.
3. **Costs savings to the utility are dominated by avoided capacity savings.** The average breakdown of cost savings for all rate structures modeled was approximately 80% and 20% for avoided capacity and avoided energy savings, respectively.
4. **The length of the CPP window is an important driver in the overall cost savings.** Increasing the peak and critical peak period window length from four hours (1:00 pm–5:00 pm) to five hours (12:00pm – 5:00pm) shifted the range of financial outcomes of various demand response tariffs. The range of outcomes for the four-hour window ranged from a net loss of $300 million for a TOU tariff with technology to a net gain of $400 million for a TOU/CPP tariff without technology, whereas the economic outcomes from the five-hour window ranged from a net loss of $50 million for a TOU tariff with technology to a net gain of $450 million for a CPP/TOU tariff without technology. Note that aside from the differences in peak hour window lengths, these scenarios use base-case assumptions detailed in the Section 8.2.
5. **Deployment of demand response programs with a four-hour peak window to a subset of residential customers will result in cost savings of less than approximately 0.25% of total wholesale electricity costs and 1% of the residential portion of total wholesale electricity costs within MISO.**

Recommendations

1. **DTE should run ProMod with the demand response tariffs and their corresponding estimated reductions that produced the greatest economic benefits.** While we are confident that our results provide a useful estimate of the potential range of economic impacts from dynamic pricing programs, it would be helpful to compare those results to those from a more sophisticated model such as ProMod.
2. **Model potential savings under a scenario in which demand growth continued at historical averages since 2008.** The economic downturn moved MISO away from the very steep parts of the supply curve, which significantly reduces the economic savings from demand response programs. Analysis with greater overall off-peak and peak demand would provide information about potential savings from demand response if electricity consumption rapidly recovers to pre-recession levels. This scenario could yield substantially different results
3. **DTE should use its pilots to test customer response to various dynamic pricing structures, various rates within those structures, and various peak window lengths.** There is significant uncertainty around the level of demand response that DTE's customers will exhibit under dynamic pricing tariffs. Pilots give DTE the opportunity to test for many different variables and track in detail how its customers will respond and the corresponding economic benefit DTE will reap in a large scale deployment of AMIs and dynamic pricing tariffs.
4. **DTE should test 2 and 3 hour CPP windows with higher differentials to test the viability of a staggered CPP tariff.** We believe this tariff represents an opportunity for DTE to distinguish itself as a cutting edge utility while benefiting economically from this novel price structure.

2 Introduction

Unlike oil or gas, electricity cannot easily be stored, which means that electricity must be generated and delivered at the precise moment it is needed – supply must always equal demand. In addition to simply meeting demand, electricity providers must maintain capacity margins, or supply that can be quickly brought on-line in the event of equipment failure or during periods of peak demand. This capacity margin is met by maintaining generation facilities that are only used during a few hours of peak demand throughout the year. For example, in most parts of the United States, approximately 10% of total system capacity is used for only 80-100 hours per year, or less than 1% of the time.[1] Not surprisingly, servicing peak periods is expensive because the facilities used to meet this demand sit idle for most of the year. The cost of servicing peak demand is illustrated by a Brattle group estimate that a 5% reduction in U.S. peak demand would result in $35 billion in savings from avoided construction of generation capacity over a twenty-year period.[2]

Unfortunately, the need for expensive peak generation capacity is increasing because demand during peak periods is growing faster than overall demand. From 2000 to 2007, electricity demand increased 1.1% per year,[3] while average summertime electricity demand increased by 1.72% per year.[4] This discrepancy between the growth of overall demand and peak demand presents a challenge for utilities. However, there are opportunities for utilities to mitigate the impact of this trend.

Most current residential electricity rate structures do not reflect the cost difference of supplying electricity in peak versus off-peak hours. Therefore, the customer has no market incentive to adjust his or her pattern of electricity consumption. Dynamic-pricing programs that charge higher electricity prices during periods of peak demand may be effective tools to shift electricity consumption to off-peak hours.

To address the challenge of the growing divergence between peak and off-peak electricity demand, DTE is interested in developing pilot programs to determine the potential of using various pricing mechanisms to change consumer demand. The goal of this Master's Project is to recommend dynamic pricing programs that our client, DTE Energy, may implement with residential customers using Advance Metering Infrastructure (AMI). The ultimate goal is for DTE to learn more about how their consumers respond to electricity prices and identify the most promising mechanisms suitable for wide-scale deployment.

Dynamic pricing programs will also have longer term impacts as plug in hybrid electric vehicles (PHEVs) become prevalent throughout DTE's service territory. These types of pricing programs and the charging times for PHEVs provide another opportunity to address the growing disparity between peak and off-peak demand. For example, in an analysis of the potential impacts of PHEVs in 2020 and 2030 in 13 regions of the United States, Oak Ridge National Lab researchers found that charging PHEVs at 10 p.m. instead of at 5 p.m. would make a significant difference in total generation costs.[5]

3 Overview of Electricity Markets and Electricity Rate Designs

3.1 The U.S. Electricity Market

In the U.S., electricity service is provided to residential, commercial, and industrial customers by investor owned and public (i.e. municipal) utilities. These companies may own generation assets that provide electricity to their customers and/or buy electricity from independent power producers (IPPs).

Understanding the wholesale electricity market is important to understanding the partially deregulated structure of U.S. electricity markets, including Michigan's. Historically, U.S. electricity markets were entirely vertically integrated, meaning a monopoly utility owned the generation assets, transmission and distribution lines (T&D), and meters in customers' homes. Because utilities earned a fixed rate of return on assets, there was concern that utilities were over-capitalized with unnecessary assets. In addition, because customers were charged average rates, there was rarely any connection between the retail price of electricity and the marginal cost of generation.[6]

The perceived problems with vertically integrated companies, combined with high electricity prices in the 1980s, led to an initiative to deregulate the electricity industry. The result of deregulation in many parts of the country, including Michigan, is that an Independent System Operator (ISO) now controls the electricity markets and dispatches power plants based on locational marginal prices (LMPs). This means the lowest-cost, base-load power plants are deployed first, with higher-cost generation facilities coming online as demand increases. Utilities that procure power from third parties pay the market clearing price, or LMP, of electricity.[7]

3.2 Electricity in Michigan

There are three distinct components to the electricity market in the Midwest, which is managed by the Midwest Independent System Operator (MISO). There is a day-ahead energy market, a real-time energy market, and a financial transmission rights market (FTR). Buyers and sellers meet on these markets, and MISO oversees the process while ensuring that energy supply is secure and reliable. The day-ahead market is the primary market on which load is scheduled. Buyers and sellers submit bids and offers for each hour of the day at various nodes throughout the transmission network. Sellers receive the market-clearing price (the LMP), meaning that if the last generating unit needed to meet demand offered their electricity at $60 per megawatt hour (MWh), all sellers would receive that price and all buyers would pay that price. The real-time market serves to smooth any imbalances, with locational marginal prices clearing every five minutes.[8]

3.2.1 Demand Characteristics in Michigan

Within DTE's service territory, peak energy demand is growing more rapidly than overall energy demand, meaning the delta between peak and off-peak demand is increasing;

serving this peak demand is very costly.[9] Unfortunately, 1) the price elasticity of demand for electricity is very low[10] and 2) rates do not reflect real-time LMPs. This means that consumers, with low-price elasticity, receive limited price signals regarding actual electricity costs. Furthermore, just as on-peak users pay less than the real-time LMPs, off-peak users generally are paying more per kWh than the LMP. This means that, in effect, off-peak energy use subsidizes on-peak consumption.

3.2.2 Supply Characteristics in Michigan

Figure 1 illustrates the geographic dispersion of Michigan's various electricity supply sources and details the contribution of those sources to overall supply.[11] Michigan derives approximately 3/5 of its electricity from coal plants, and an additional 1/4 from nuclear generators, both of which primarily serve as base-load power sources. Most of the remaining demand, much of which comes at peak times, is met by natural gas power plants. Michigan also has a large number of hydro-electric and landfill gas resources.[12]

Michigan is no different than many parts of the country in that the marginal price of electricity increases dramatically during peak periods. Figure 2 below is specific to California, but it illustrates just how expensive it is to service peak demand.[13]

Figure 2 - Supply Characteristics in Michigan

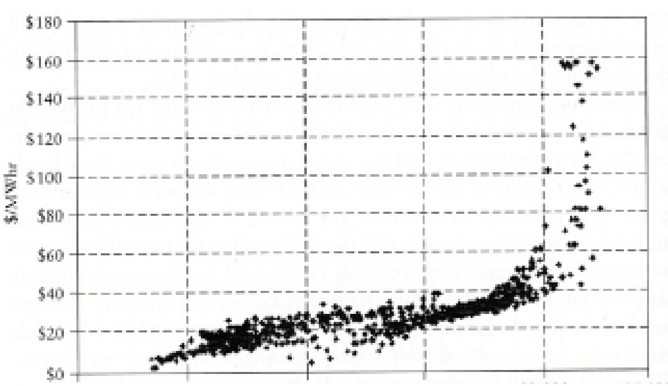


Figure 1 – California Supply Curve

3.2.3 *Utility Business Model in Michigan – How Utilities Make Money*

Investor owned utilities in Michigan earn money based on a fixed rate of return on equity agreed to by the Michigan Public Service Commission. DTE customers, for example, pay for all costs associated with generating and delivering electricity plus a fixed rate of return. Consumer prices are set in a manner that seeks to ensure cost recovery as well as a return on equity.

3.2.4 *Current Rate Plans in the State of Michigan*

In Michigan, nine investor-owned utilities (IOUs) and nine cooperatives serve over 4 million customers.[14] DTE and Consumers Energy, the two largest providers in the state, serve more than 87% of these customers and account for more than 88% of state electricity revenues.[15]

DTE serves the majority of its customers with a traditional rate structure. The most popular plan consists of a monthly service charge, and a two-tiered rate per kWh. The first 17kWh per day, averaged over one month, costs 6.726¢ and each additional kWh costs 8.136¢. In addition to this standard plan, DTE also offers several other rate structures including plans with seasonal pricing, on-peak and off-peak pricing, and utility interruptible service. However, these plans serve only a small fraction of customers. The current time-of-day program, for example, is only available to 10,000 customers. An advance electricity meter is required for these time-of-day rates. Details of these plans can be found in appendix A.

In addition to these rate plans, DTE offers a renewable energy option called Green Currents. Enrollees in this plan ensure that their electricity is supplied by renewable wind and biomass energy sources. Customers can choose to receive 100% of their electricity from renewable energy sources for a premium of 2 ¢ per kWh, or they can purchase 100 kWh blocks of renewable energy for $2.50. As of January 2010, DTE had enrolled over 18,300 customers in this program, well above initial expectations of 4,000.[16]

The second largest supplier of electricity in the state is Consumers Energy. Unlike DTE, the standard rate plan for Consumers has seasonal price differentials. From October to May, customers pay 4.7517 ¢ per kWh for all electricity consumption. During the peak demand months from June to September, consumers pay 4.7517 ¢ for the first 600 kWh per month and 8.4687 ¢ for each additional kWh of electricity. Consumers Energy also offers a time-of-use rate program, but this rate is limited to just 10,000 customers. Details of Consumers Energy rate plans can be found in Appendix B.

Like DTE, Consumers Energy offers a renewable energy option called Renewable Resource Program. Consumers may procure all of their electricity from renewable sources for an additional 1.667 ¢ per kWh or purchase 150 kWh blocks of renewable energy for $2.50 each.

Customers that purchase more than 100 blocks of renewable energy a month receive a bulk rate of $2.00 per 150 kWh.

In addition to the major electricity producers, several of the smaller electricity suppliers offer innovative rate structures. Wisconsin Public Service for example offers time-of-use service with two different peak and off-peak time windows. The utility also has a program in which they install a peak interrupter on heaters, air conditioners, or water heaters. A selection of rate plans from other utilities can be found in Appendix C.

3.3 Dynamic Pricing Rate Designs

3.3.1 Critical Peak Pricing

Critical Peak Pricing (CPP) is a fairly new rate program being offered by various utilities throughout the country. CPP tariffs are, in essence, a form of TOU programs except that CPP is even more targeted. Instead of daily on-peak times as in TOU rate structures, the on-peak times are limited to just a few days per year when demand is expected to be highest, such as during heat waves when the entire population runs their air conditioning unit. The primary goal of the program is to shift load from on-peak to off-peak hours on these peak demand days. CPP rate plans typically designate a specific time window for the CPP tariff, such as between 2pm and 7pm, and limit the number of event days, typically 6 to 15 per year, that may be called so as to not create undue hardship for the customer. Participants in this rate program are offered discounted power during off-peak hours in return for being charged much higher rates during critical hours. CPP on-peak rates typically range between 400% and 700% of the off-peak electricity rate.[17] This disparity between the prices in off-peak and critical-peak hours is designed to create the financial incentive to reduce electricity consumption during extremely high demand days. A review of CPP programs indicates that this pricing structure has been the most effective at shifting demand during critical peak periods.

In the case of PG&E's CPP program, customers pay three times their base tariff between noon and 3pm on event days, and five times their base tariff between 3 and 6pm. PG&E has a separate but related program named "SmartRate" in which residential customers pay an additional $.60/kWh on top of their off-peak tariff for all electricity used during peak-hours on an event day. Customers receive a $.03/kWh credit for electricity used during non-peak hours on non-event days for the months June through September.[18]

The SmartRate program was advertised to customers via direct mail; over 135,000 customers were notified, and 10,000 enrolled within three months. Customers were given a $50 visa card as an incentive to enroll early and were offered bill protection to guarantee them an annual bill of no more than the previous year. Once enrolled, customers were sent a welcome kit, energy saving tips, and a confirmation letter. Specifically, customers were given methods for both reducing their overall load and shifting it from on-peak to off-peak.[19] An interesting point to note about this program is that a disproportionately high number of low-income households enrolled. In addition, it is important to note each household's annual electricity consumption. Those homes with high consumption are also those that are more easily able to displace and reduce loads on event days. Some high-consumption households reduced their demand by five times more than did low-consumption homes.[20] However, while high-use consumers are able to displace load more effectively than low-use consumers, it was the low-use consumers that saved considerably more on a percentage basis on their annual electric bill.[21] Customers in the high-use group that earned less than $50K/year saw 5-10% decreases in their electric bill on an annual basis. This group of customers is a particularly healthy segment to target because of their ability to be offered substantial savings while displacing large amounts of load.[22]

On average, residential customers decreased their load, as compared to a reference baseline, by .4 kW on event days, amounting to a 16.6% decrease in load. As expected, customer electricity consumption shifted out of the 2 p.m. – 7 p.m. range.[23] See Figure 3 for high-level data on the program.

Type of Results	Avg. Customer
Customer Class	Residential
Event	Average Event
Participant Category	E1
Event Date	Average Event
Event Notification	Day Ahead
Event Start	14:00
Event End	19:00
ACCOUNTS FOR EVENT	8,758
TOTAL ENROLLED ACCOUNTS	8,758
Avg. Load Reduction for Event Window	0.40
% Load Reduction for Event Window	16.6%

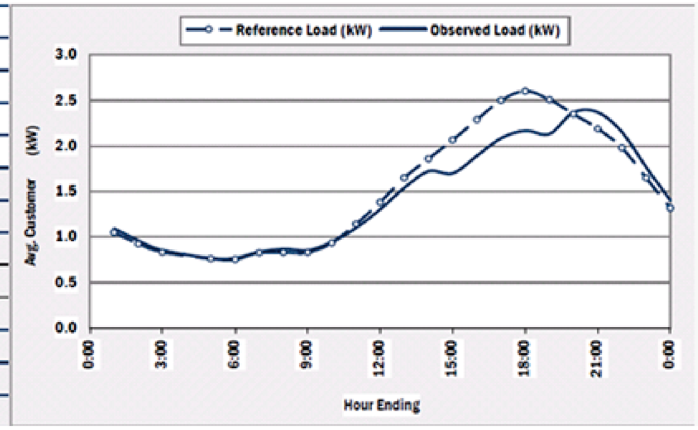


Figure 3 - Overview of PG&E CPP Program

3.3.2 Critical Peak Pricing Results

The pilot pricing programs implemented by the three largest California utilities in 2003 and 2004 included a CPP plan. Under the CPP plan consumers paid 59¢/kWh during event periods compared with 13¢/kWh under a standard rate plan. The pilot resulted in demand reduction during event periods of just less than 13% in 2003 and reduction of almost 14% in 2004.[24]

A 2006 Xcel Energy pricing pilot also included a CPP rate structure. The actual pricing of CPP electricity is not published in the literature, but results of the pilot showed a demand reduction between 31% and 45% during critical peak periods.[25] The observed demand reduction was even greater when the CPP program was bundled with a TOU tariff structure and a programmable communicating thermostat.

In 2006 and 2007, PSE&G conducted a pricing pilot study that bundled CPP and TOU together. A discussion of bundled rate programs will be discussed in more detail in a following section, but the results of this pilot demonstrate the effectiveness of CPP in reducing peak demand. Under the program, customers were charged 4¢ for off-peak consumption, 17¢ for on-peak consumption, and 69¢ for critical peak consumption. In 2007, the rate for critical peak electricity was increased even further to $1.45 per kWh. The results of the pilot estimated that the TOU rates were responsible for a 3%-6% reduction in demand during peak events, while the CPP rate was responsible for an additional 14% reduction. Thus, total reductions were between 17% and 20% during critical peak periods. When coupled with a communicating programmable thermostat, demand reductions were 21% due to TOU rates and 26% for CPP rates for a total reduction of 47%.[26]

A concern about critical peak pricing programs is how customers will respond to multiple CPP days in a row. Since high demand days are typically associated with heat wave events, it is often the case that utilities face consecutive critical event days. Customers may develop fatigue after multiple event days and not reduce demand as much at the end of a sequence of critical demand days. However, history indicates that the opposite is observed. A review of PG&E's Smart Rate Tariff program found that customers were actually better at shifting load on the third day of each event cycle than on the prior two days.[27]

These pilots are just a few of the many CPP pilots that have been implemented to date. Each demonstrates the effectiveness of CPP pricing to reduce peak demand. The data also supports bundling CPP programs with TOU rates and enabling technologies for further demand reduction.

3.3.3 Time-of-use Pricing (TOU)

Time-of-use (TOU) pricing structures have sprung up all over the country as a result of improved metering infrastructure. Meters are now capable of monitoring not only how much energy is used, but also when it is used. Utilities have taken advantage of this new technology and created a residential pricing plan to encourage electricity usage during off-peak hours and to discourage electricity usage during on-peak hours. For example, Baltimore Gas and Electric (BGE) offers a program with five different rates based on when electricity is consumed (see Figure 4 below). The tariff structure provides electricity at a rate of 10.321¢/kWh from 7-10am and 8-11pm, and 9.305¢/kWh between 11pm and 7am. The savings over the non-TOU rate of 11.83¢/kWh creates incentives for homeowners to use their electricity during these time periods. For weekdays between 10am and 8pm, homeowners are charged 15¢/kWh, creating a substantial incentive to refrain from consuming during that time period.[28] Overall, the goal is to flatten the load curve by reducing on-peak demand and increasing off-peak demand.

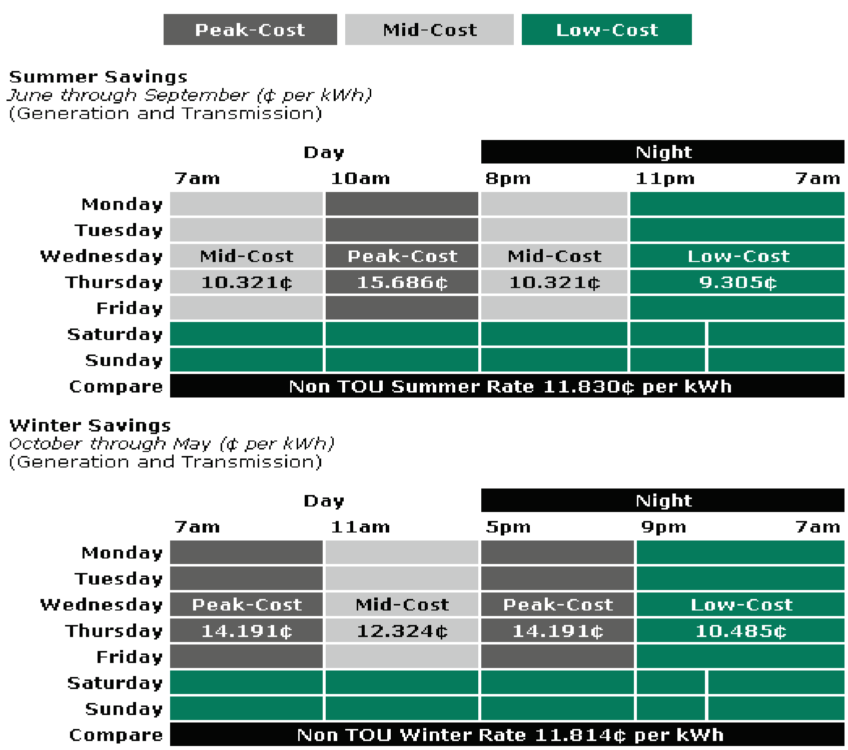


Figure 4 - Overview of BGE TOU Program

One commonly stated shortcoming of TOU rates is its inability to create additional incentives on high system stress days, such as peak event days that CPP programs intentionally target.[29] This occurs because the large disparity between on- and off-peak rates that exists in CPP programs is not as prevalent in TOU rates. TOU pricing structures are only marginally effective at altering electricity demand on critical days because the price differential for TOU rates only reflects average marginal cost for peak hours.[30]

It is on these peak days, when the utility is bumping up against system capacity, that shifts in consumption from peak to off-peak periods is most valuable to the utility. The result is that TOU plans do flatten the load profile for the utility, but the price signal is insufficient to significantly flatten the load on the highest demand days.

3.3.4 TOU Results

In 2006, Xcel Energy rolled-out a pilot program that included a TOU program. In the study, TOU rate structures resulted in a demand response of just -5.19% during peak periods.[31] In 2003 and 2004, the three major utilities in California collaborated on a pricing pilot that included a TOU plan. Customers were charged 9¢/kWh for off-peak and 22¢/kWh for peak consumption compared to 13¢/kWh for the standard rate plan. In 2003, peak period demand reduction was found to be 5.9%, but in 2004 there was no measurable reduction in peak demand.[32]

Idaho Power Company implemented a similar pilot program in 2006 and the results were also unfavorable. The results of the study showed no shift in electricity consumption for consumers who were on the TOU rate plan.[33] The difference between peak and off-peak rates in this program was less than 100% (4.5¢ to 8.3¢), which may explain the lack of consumer response, but the fact that no demand response was observed is not favorable for TOU plans. While these are just a few examples of TOU studies, similar results have been observed in other TOU programs.

3.3.5 CPP/TOU Pilots

Some utilities have implemented pilots that combine the elements of both TOU and CPP (or RTP and CPP) with very promising results. There have been a variety of studies designed to identify the most effective ways to influence customer demand patterns. In general, these studies have indicated that coupling CPP with block rate TOU pricing is highly effective relative to the other approaches. One central argument for combining CPP and TOU is that TOU plans do not create sufficient incentives to conserve energy on CPP event days, while CPP days only address demand during a very small number of days.[34] A combined CPP/TOU plan addresses peak demand throughout the year *as well as during* critical peak periods.

3.3.6 CPP/TOU Results

The exact amount of energy savings from a combined TOU/CPP program will depend on a number of factors, including the total number of price windows, the time(s) of day the price windows are in place, the amount of increase (in cents) from one price window to the next, the presence of an enabling technology, and the extent to which customers have been educated about the program. Total energy consumption is likely to decrease by a minimum of 1-6%.[35]

There are a number of TOU/CPP pilots that have illustrated the effectiveness of this approach versus others. A 2004 pilot involving 250 residential customers from Missouri further supports the notion that enabling technology is critical to demand response. In this pilot, there were three groups of customers, those subject to TOU rates, those subject to TOU and CPP rates, and those subject to TOU and CPP rates with the addition of an enabling technology (a smart thermostat). The technology-enabled group demonstrated statistically significant reductions in demand during all periods (off-peak, on-peak, mid-peak, CPP), whereas the TOU and CPP group without enabling technology only demonstrated statistically significant reduction in demand during CPP periods (and less reduction than the technology enabled group). The TOU-only group demonstrated no statistically significant shifts in demand.[36]

Another pilot in Washington state further illustrates that combining CPP and TOU with enabling technology can lead to significant demand response. In this pilot, the utility was able to send price signals to select homes, and consumers were able to pre-program demand response preferences. The test groups included a fixed price group, a CPP/TOU group, and a RTP group. Both the RTP and CPP/TOU groups saved approximately 30% on their electricity bills, but only the CPP/TOU group significantly reduced their overall demand (demand reduction was approximately 20%).[37]

One pilot program by Xcel Energy in the Denver Metropolitan area found that of the RTP, TOU, or RTP + TOU, the combination of RTP and TOU pricing led to the most demand response (though enabling technology was critical to this).[38]

3.3.7 Real-Time Pricing

Real-time pricing (RTP) models enable utilities to charge customers the actual real-time costs of electricity production based on supply and demand. Technological advances in metering infrastructure and wireless communication technology have created the ability for utilities to communicate real-time electricity price information to its customers. As a result, several utilities have launched RTP pilots to test the effectiveness of shifting load from on-peak to off-peak.

One shortcoming of real-time pricing is its inability to control or shift loads except on those days where demand severely outweighs supply. In general, this imbalance only happens on a few extremely hot days each summer, such as CPP event days, where households and businesses run their air conditioners extensively. As a result, real-time pricing generally only shifts demand or induces conservation for a few hours on a few days each year.[39]

On the behavioral side, it is important for utilities to understand what drives consumers to sign-up for this type of pilot and what types of behavior a pilot is expected to induce. For the former, research on the ComEd RTP pilot demonstrates that consumers joined the program primarily to save money. Environmental reasons were also cited, but to a much lesser extent.[40] Of customers who chose not to try the program, most cited their belief that their expected savings did not warrant the hassles of switching. Many others believed the program to be risky and complex relative to their current price plan.[41]

3.3.8 Real Time Pricing Results

From an economic perspective, real time pricing should create the most economically efficient consumption patterns of electricity. By charging the actual price of electricity, consumers will adjust their demand accordingly and only consume electricity when the marginal cost is less than their marginal benefit. In reality, however, RTP by itself has had limited success. Despite sending the correct price signals, it is too cumbersome for consumers to monitor the constantly moving price of electricity. The result is that consumers do not pay attention to the price and adjust their consumption patterns. RTP, however, may be an appropriate tool when coupled with enabling technologies. Enabling technologies can automate the customer response to the constantly fluctuating price of electricity and have been shown to reduce consumer demand.

Due to the clear issues of consumer's ability to effectively monitor real-time prices, there is limited data on pure RTP programs. Commonwealth Edison, a utility in Chicago, has been conducting a real-time pricing pilot since 2003, and several observations have been made about the effectiveness of this program. The pilot has demonstrated that participating customers are significantly price elastic to electricity prices (an interesting contrast to other studies indicating that consumers are price inelastic), and will induce shifts in behavior that move electricity demand from on-peak to off-peak periods. Most substantively, a one standard deviation shift in price effectively induced 25% of the households to reduce demand by 75W. Overall, the program saw a drop of 100-200W during daytime hours, which equates to a 5-14% load reduction.[42]

In 2006, Community Energy Cooperative in Illinois unveiled a large-scale RTP program. This was not a true RTP program as prices were set at the day-ahead rates and did not adjust to the actual rates at the time of consumption. Additionally, consumers were notified by phone whenever prices rose above 13¢ per kWh. During the highest priced day, consumers under this program reduced their consumption 15% compared to consumption under standard electricity tariffs.[43]

In 2006, the Pacific Northwest GridWise Testbed Demonstration unveiled a RTP program in the state of Washington. This program was a true RTP program as customers paid the market rate for electricity and the price was adjusted every five minutes. Consumers were outfitted with smart-metering equipment that allowed them to adjust their demand automatically given the current rate of electricity. Consumer preferences were set using a web interface and could be overridden at any time. Customers under the RTP plan reduced their peak consumption by 15%, compared to 20% for a TOU/CPP group.[44] Interestingly, RTP customers did not reduce their overall energy consumption indicating that this rate program may result in substitution of off-peak consumption for on-peak consumption rather than conservation.

3.3.9 Peak-Time Rebate (PTR) Programs & Results

These programs offer a rebate to customers who reduce their electricity demand on critical peak days when compared to a reference level on a non-CPP day. Southern California Edison conducted a pilot PTR program in the summer of 2005. This PTR program offered consumers 35¢ for each kWh reduction below a reference consumption level. Customers who enrolled in this rate plan were found to reduce their demand by 12% compared to the control group on critical peak days.[45]

Ontario Energy Board also tested a PTR program from 2006 to 2007. Similar to the SCE program, this tariff gave a rebate of 30¢ per kWh for reduction on critical event days compared to a reference on a non-event day. The PTR program resulted in a shift of 17.5% of demand on critical event days to off-peak hours as well as a 7.5% reduction in demand.

While the number of experiments on PTR programs is limited, preliminary studies support their effectiveness at reducing demand. The perception of a PTR program (receiving money) instead of a CPP program may also be a useful characteristic of these programs. While the data on these programs are limited, DTE should seriously consider a PTR program as a part of its demand response pilot.

3.3.10 Green Power Programs

According to the National Renewable Energy Laboratory, over 850 utilities offer green power programs that serve over 600,000 customers.[46] Green power programs allow consumers to pay a premium on their electricity rates to ensure that their electricity is coming from renewable resources such as wind, solar, hydro, biomass, and landfill gas. Despite the downturn in the economy, green power sales increased by 20% in 2008 compared to the prior year.[47]

Although demand-shifting programs like TOU and RTP do not source energy specifically from renewable resources, there may be opportunities to brand these as green programs. Many of the power plants that serve peak demand periods are inefficient generating facilities with high emissions factors. By shifting consumption from peak periods to off-peak periods, the higher-emissions plants will have less uptime, possibly resulting in emissions reductions. The validity of this “green” argument, however, is not clear and requires an analysis of the marginal emissions rates of the power displaced compared to the marginal emissions rate of facilities operating during off-peak periods, as well as possible changes in overall electricity consumption. For example, a study by the University of California Energy Institute found that time varying prices would result in increased emissions of SO_x and NO_x, but decreased emissions of CO_2.[48] With the majority of base-load power supplied by coal generation facilities, and peak load power served by natural gas plants or coal in Michigan, a shift of consumer demand from peak to off-peak may not result in reduced emissions.

Given the growth and popularity of green power programs, DTE should consider the possibility of marketing demand-shifting rate programs as an environmental choice. However, a careful analysis of the shift in supply and overall change in electricity consumption should validate the authenticity of these claims.

4 Dynamic Pricing and Technology

Almost all residential electricity consumers have electricity meters that measure only total electricity consumption. With no infrastructure in place to capture the time at which people are consuming electricity, utilities are unable to implement dynamic pricing programs.

In the 1990s, the development of communications technology led to the creation of automated meter reading (AMR) technology. AMR was a significant upgrade from traditional analog meters, allowing utilities to collect consumption data by wireless transmission as the meter readers walked or drove by the houses. However, AMR was still limited to collecting cumulative electricity consumption and did not differentiate consumption by time of day.

Further advancement in communication technology led to the development of Advanced Metering Infrastructure (AMI). The characteristics that define AMI include continuous available communications, interval measurement, dynamic pricing, information to the customer, frequency of transmittal, and information to the utility.[49] These characteristics are defined below.[50]

> *Continuous Available Communication* – The utility will be able to communicate with the metering device at any time through a fixed network. Through the available communication protocol, the utility may be able to collect data and change the measurement parameters of the meter.
>
> *Interval Measurement* - AMI devices collect electricity usage data on time intervals. At a minimum, this data should be divided into hourly intervals.
>
> *Dynamic Pricing* – Using data from interval measurements, AMI should be able to implement dynamic pricing plans including RTP, TOU, and CPP.
>
> *Information to the Customer* – AMI should allow for information to be provided to the customer that enables dynamic pricing programs, including information about consumption and current prices.
>
> *Frequency of Transmittal* - An AMI should be able to transmit information to the utility at least daily. Devices may also allow transmittal of information directly to the customer.

In addition to these characteristics, AMI are now typically compatible with a communication standard like ZigBee that can be used to communicate with and control electronic devices within the household. This is an important component of the implementation of demand response programs as this communication standard allows consumers to program either an automatic shut-off or a reduction of the energy consumption of home loads during periods of peak energy prices. AMI alone does not allow this functionality; additional "smart" in home devices are required. Consumers often do not change their behavior when faced with dynamic electricity pricing due to cognitive market failures since it is too difficult to keep track of fluctuating prices and to identify how to effectively reduce consumption. Standards like ZigBee can help overcome this barrier to dynamic pricing programs, by automating the behavior change.

Despite the benefits of AMI, deployment has been slower than many people expected. The deployment of these devices faces many barriers including the cost of the devices, uncertainty in device and communication standards, and uncertainty whether utilities may include the cost of the devices in their rate base. However, with the recent announcement by President Obama to deploy 40 million smart meters, as well as the growth of revenue decoupling, AMI seems poised for large-scale deployment into the market.

Michigan in general, and DTE specifically, appear to be ahead of the curve in this regard. In July of 2008, Itron OpenWay signed a contract with DTE to provide 2.6 million electric meters over the next six years. Itron's AMI technology provides capability for interval data collection, TOU metering, remote disconnect, outage detection, net metering capability, and ZigBee home network connectivity.

5 Attributes of Successful Demand Response Programs

In order to inform recommendations to DTE as to which tariff programs should be considered for upcoming pilots, we consolidated information learned from previous pricing pilots, many of which are discussed above. The following section outlines factors that are important in designing a successful demand-response program:

5.1 Enabling Technology Improves Demand Response

It is well documented that enabling technology increases demand response. According to a comprehensive 2008 *Price Elasticity of Demand for Electricity* by EPRI, a key conclusion is "there appears to be considerable potential for deploying enabling technologies to foster greater price response, perhaps surpassing what can be achieved by complex pricing plans[51]." Furthermore, according to the Brattle Group's 2009 Household Response To Dynamic Pricing Of Electricity—A Survey Of The Experimental Evidence, "Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing tariffs induce a drop in peak demand that ranges between 13 to 20 percent. When accompanied with enabling technologies, the latter set of tariffs leads to a drop in peak demand in the 27 to 44 percent range.[52]"

5.2 What is Enabling Technology?

Enabling technology, by definition, is "equipment and/or methodology that, alone or in combination with associated technologies, provides the means to generate giant leaps in performance and capabilities of the user[53]." More narrowly, with respect to dynamic pricing and demand response, enabling technology is some combination of hardware and software that allows the end customer (i.e. residential household):

1. To automate control of their load consumption according to specific price and time ranges

2. Transparency into electricity prices
3. Knowledge of individual and household load electricity consumption levels

5.2.1 Enabling Technology Devices

There are several devices and software programs and platforms that are considered enabling technologies for demand response programs. A brief overview follows:

1. Advanced Electric Meter (AMI):
   1.1. An electric meter, new or appropriately retrofitted, which:
        1) Is capable of measuring and recording usage data in time differentiated registers, including hourly or such interval as is specified by regulatory authorities,
        2) Allows electric consumers, suppliers and service providers to participate in all types of price-based demand response programs, and
        3) Provides other data and functionality that address power quality and other electricity service issues.
2. In Home Display:
   2.1. A digital display (typically employing Zigbee technology) that allows consumers to closely track their electricity consumption and receive messages or alerts from their utility provider
3. Smart Thermostat
   3.1. A digital device that provides the user with the capability to monitor HVAC energy consumption, respond to fluctuations in electricity prices and manage energy loads. The user can dictate how the thermostat should behave in the presence of various price tiers as well pre-set household heating and cooling levels for different times of the day.
4. Web Based Consumer Portal
   4.1. A browser-based Internet portal that enables the user to monitor, manage and control the energy consumption and each of the smart devices in your home. It allows the user to receive information and pricing signals from the utility and compare usage to neighbors.
5. Smart plug / Smart Appliance
   5.1. An electrical outlet / appliance that allows the user to measure and control the energy consumption load plugged into outlet

5.3 Targeting High Consumption Homes May Be an Effective Strategy

The California Statewide Pricing Pilot from 2003 and 2004 demonstrated that CPP programs can be effective at reducing demand. That study also demonstrated, perhaps not surprisingly, that high-use customers decrease their demand the most on CPP event days (one additional note here is that those people with the lowest demand benefited the most economically, in percentage terms, from the CPP program). As a result, a program targeting high-use customers may be more cost-effective than a rate targeting all customers because low-use customers do not exhibit a statistically significant reduction in energy use on CPP event days. It is important to differentiate between electricity usage and income level. While there may be a positive correlation between the two, it is important to highlight that response to CPP is consistent across income levels (i.e. low-income, high-usage customers respond identically to high-income, high-usage customers).[54]

The results of a 2008 CPP study of Pacific Gas & Electric customers were consistent with the results from the 2003 and 2004 statewide program described above. Specifically, it demonstrated that the largest users saved the most amount of energy for the utility; customers using more than 15000 kWh per month saved 5 times more energy than did users using less than 5000 kWh.[55]

5.4 Larger Differential Between Peak and Off-peak Rates Leads to Greater Savings

It may seem intuitive that, for TOU rates, the higher the peak price, the greater the overall customer savings. Nonetheless, this is a critical point to consider when designing pilots. For example, a 1997 TOU pilot in New Jersey detailed that higher prices incentivize greater savings. In the pilot, customers faced three different rates, specifically off-peak, shoulder, and peak rates. The "high shoulder/peak" groups faced prices of 6.5¢, 17.5¢, and 30¢, whereas the "low shoulder/peak" group faced rates of 9¢, 12.5¢, and 25¢, respectively. The high rate design group saved 50% over and above the low rate design group during the peak and shoulder periods. Clearly, a high price differential between peak and off-peak rates is important to influencing consumer responses.

An additional outcome of the New Jersey pilot was that, following CPP events, usage during off-peak and shoulder periods was substantially higher relative to a control group not subject to CPP pricing.[56]

5.5 Marketing and Education

One message that is consistent throughout the pilots is the importance of educating customers about the programs and about the steps that each customer can take to reduce consumption. Customers may be inclined to think that they cannot curtail demand, meaning education about strategies for demand reduction is essential to the success of a pilot.[57] This issue relates in part to the fact that customers typically cannot decipher what leads to increases or decreases in consumption simply by reading a typical electric bill.[58]

Numerous successful pilots have had marketing and educational components geared toward signing-up customers and then educating them about the rate structures they will face as well as about strategies that can be used to reduce demand. In many ways, education and marketing is a condition to having a successful pilot. The New Jersey pilot discussed above used a financial incentive ($75-$100) to participate in the pilot, and many of the pilots involved free installation of the enabling technology. For the 2008 PG&E CPP program discussed above, customers were offered $50 Visa cards to sign up, and they were presented with a welcome packet as well as directions on how to save energy. Further, PG&E's program guaranteed its customers that they would not see a bill increase, at least for the near term. Bill protection could be an important lever to use because it provides risk-averse customers with an insurance against higher bills.[59,60]

5.6 Customer Notification

Customer communication methods are critical to the success of CPP programs. The PG&E study highlighted that there are likely some limits to the percentage of participants that are successfully notified; PG&E's success rate rose from 65% on the first event day to a consistent success rate of 80-85%. This success rate indicates that there may be a small, but important minority of customers that will be unreachable on any given event day. Hence, a certain number of customers cannot be relied upon to respond to critical peak events.[61]

PG&E notified customers via phone calls (either voicemail or live person reached) and email, but other methods could be explored. Doctor's offices have found success, for instance, by text messaging reminders to patients the day before appointments.[62]

5.7 Bill Protection

A challenge facing utilities trying to enroll customers in demand-response pricing programs is the concern consumers have that their rates will go up. In response to this concern, many utilities offer bill protection for their customers who enroll. A typical bill protection program will refund any customers whose electricity bills rise under a demand response tariff (over a 12-month commitment period). After an initial period, the customer typically is no longer eligible for bill protection refunds. Southern California Edison[63] and San Diego Gas and Electric[64] are just a couple of several utilities that have offered bill protection programs for customers who enroll in demand response rate plans.

5.8 Experimental Design

The results of previous demand response programs described above provide direction for DTE's upcoming pilots. However, the most important information will come from the results of pilots themselves, so careful experimental design will be crucial to the success of the demand response program chosen. This may sound like common sense, but consumer electricity demand is driven by numerous factors and effectively controlling for all of these factors to isolate the effects of demand response tariffs is challenging.

6 Conclusion from Literature Review and Research

The findings from our research provide an overview of the results of previous demand response tariff programs and of the important factors to consider when designing pilots. Based on this research, we developed eleven pilots that we believe could provide meaningful shifts of residential electricity usage. This paper will only forecast actual demand shift for four of these pilots due to the intensive nature of the analysis. However the methodology used can be replicated in future research for the other pilots.

Among these eleven pilots, six are conventional designs; they include CPP, CPP with enabling technology, TOU with enabling technology, TOU / CPP with enabling technology, PTR with enabling technology, and RTP with enabling technology. All of these programs are discussed in detail above. The other five pricing plans – Staggered CPP, CPP Subsidizing

Renewable Energy, TOU/CPP Block Rate Pricing, and Point Rewards – are innovative in that they have not previously been tested. These programs are described in detail below.

6.1 Staggered CPP

CPP has been heralded for its ability to curb electricity demand during peak periods, and the pricing structure is effective for numerous reasons. First, the CPP window is relatively short (4-7 hours) and only occurs a few days a year. This makes it easier for people and companies alike to shift their demand to off-peak for just a few hours each year and therefore does not demand a shift in habitual energy use. Second, the electricity users are given a warning about the CPP event through different means such as text messages, email, and website postings. People are notified of the event, and are prepared to curtail their usage during the peak times.

Of course, CPP programs can be improved upon. Research shows that on event days, electricity usage is reduced substantially at the outset. In other words, demand is greatly reduced in the first couple of hours of the on-peak window. However, as the CPP event progresses demand reduction is reduced during the last several hours relative to the first few hours of the window.

There is an opportunity for DTE to create a new pricing structure that creates a win-win situation for both the electrical consumer and the utility. Staggered CPP windows would enable the utility to shorten the event window for individual customers, while improving upon the amount of demand reduced. This would be done by creating shorter, but staggered, CPP windows for different customers. In addition, prices for this shorter window would be increased over and above what they would have been for a longer event window. This further incentivizes customers to curb their electricity usage during these shorter peak times.

For example, customers A, B, and C will all have their windows shortened to three-hour blocks, instead of six. However, A's CPP window will run from 2-5pm, B's from 3-6pm, and C's from 4-7pm. Because of the shorter period of time, and the higher CPP, we would expect to see a significant reduction over the customer baseline.

DTE could further refine this pricing structure by offering different CPP pricing based on the CPP window chosen. We would expect residential users to prefer having their CPP window in the middle of the day, as opposed to the early evening when people arrive home from work. As a result, DTE could charge more money, either via a flat rate or per kWh, for the CPP windows that are in higher demand.

Overall, consumers are expected to be happier with a shorter CPP event window, especially if they are able to choose the window. Similarly, DTE can expect to see a greater percent reduction on event days than would have occurred using a traditional CPP program. Results from Brattle show that by doubling the CPP price from 50 cents to $1.00, CPP reductions increase from 24% to 32%. This increase in savings may support the validity of a staggered CPP approach. (See Appendix G –Tariffs and Expected Demand Reductions Using Prism Simulation, rates 1 and 2)

6.2 CPP Subsidizing Renewable Energy

The structure of this program is identical to a typical CPP program, but it incorporates concepts taken from DTE's GreenCurrents program. For instance, a portion of the CPP rate could be set aside to fund renewable energy. If the critical peak rate is $0.50 per kWh, then an additional surcharge could be designated specifically to fund renewable energy or energy efficiency investments. The benefits of such a program include incentivizing environmentally conscious customers to participate and educating consumers about the importance of shifting demand from on-peak to off-peak.

6.3 TOU/CPP Block Rate Pricing

This program is designed to incent conservation with consumers facing increasing prices the more energy they consume. The structure of this program is similar to that of TOU and CPP programs in that prices vary depending on whether use occurs during off-peak, shoulder, on-peak, or critical peak periods. However, prices increase not just based on time of use, but also based on total amount of energy consumed during a day or month.

As an example, during a critical peak period, the first 10 kWh of electricity on any given day may be $0.50 per kWh whereas the next 10 kWh would be $1.00 per kWh. The blocks could be monthly instead of daily, meaning use during critical peak periods of less than 100 kWh in any given month could be $0.50 per kWh while any use in excess of 100 kWh in a month would be $1.00 per kWh. Block rates could be applied not only to critical peak periods but also to on-peak periods. Again, such an approach could further incentivize conservation by consumers.

6.4 Point Rewards

Rewards programs in various industries have been in use since the late 1800s, and have generally been used as a type of loyalty program.[65] These programs, made famous by the airline industries, have had great success at building customer loyalty and at incentivizing customers to purchase more of one company's product. Recently, points programs such as the mileage programs used by airlines, have been adopted by other industries to promote a desired behavior. For example, RecycleBank was founded on the premise of rewarding people with points for recycling. These points can be redeemed at a variety of participating vendors.

DTE has the unique opportunity to offer a points program to its customers for curbing electricity consumption during peak times, and shifting load to off-peak times. The program would work by offering a specified number of points during every hour of the summer that DTE wanted consumers to reduce demand. For example, the hours between 1pm and 6pm on critical peak days would be rewarded with the largest number of points. So, when a customer reduces demand below some base level for three hours of that day, the customer would receive the specified number of points.

The base level could be calculated in many different ways. However, prior studies show that using the average consumption of the last five non-peak event days offers the best method for establishing a base line. This average should be multiplied by 1.25 to provide additional "room" over which the consumer can reduce demand.[66] In other words, the utility makes it marginally easier for the consumer to earn points and creates a greater incentive to do so.

Points could be redeemed for various types of prizes such as airline tickets or merchandise. In addition, DTE could partner with various venues throughout Michigan so that high point scorers could receive better hospitality treatment such as a separate line at various stadiums. This creates publicity for the program while giving the largest demand reducers public recognition for their efforts. DTE could partner with one of the many credit card companies that already run similar reward programs to take advantage of their knowledge and ability to manage the program.

7 Analysis

7.1 Overview

In consultation with DTE, we conducted an in-depth evaluation of three of the eleven pricing programs discussed above. We selected these three pricing programs based on feedback provided by DTE about their level of interest in the different programs as well as our judgment about the feasibility of actually modeling the different programs (because some of the programs are novel, there is limited data on which to build assumptions about potential for demand shifting and/or conservation). Our team and DTE mutually agreed to evaluate TOU, TOU/CPP, and TOU/PTR, and it was further agreed that we would perform scenario analyses for these pricing programs by evaluating the significance not just of the pricing programs themselves, but also of other factors such as level of demand response (high, medium, or low), presence of enabling technology, and demand-response pricing penetration level (high, medium, or low). We determined that a scenario-based approach was the best way to address uncertainty in the model.

There are two primary elements to this in-depth evaluation. First, to determine potential energy and cost savings associated with implementing various pricing programs, we built a dispatch model to approximate supply as well as residential electricity demand in MISO and then used the model to calculate the impact that certain pricing programs would have on residential demand. Second, we developed specific scenarios that could be fed into the model to test uncertainty.

The sections that follow provide detail about the model and the specific parameters of the scenarios we developed.

7.2 The Model

Figure 5, Figure 6, and Figure 7 depict the structure of the MISO dispatch model that we used in the analysis. The model is designed to simulate hourly supply and demand within MISO to determine which power plants are dispatched along with the hourly wholesale price of electricity. Figure 5 depicts the modeling of our base case scenario in which no demand response pricing program is deployed. Figure 6 shows how we incorporate the elements of demand response pricing programs into the model. Figure 7 shows how we compare 1) the cost of electricity generation and 2) emissions levels with and without demand response pricing programs. The sections that follow describe the model and its components in detail.

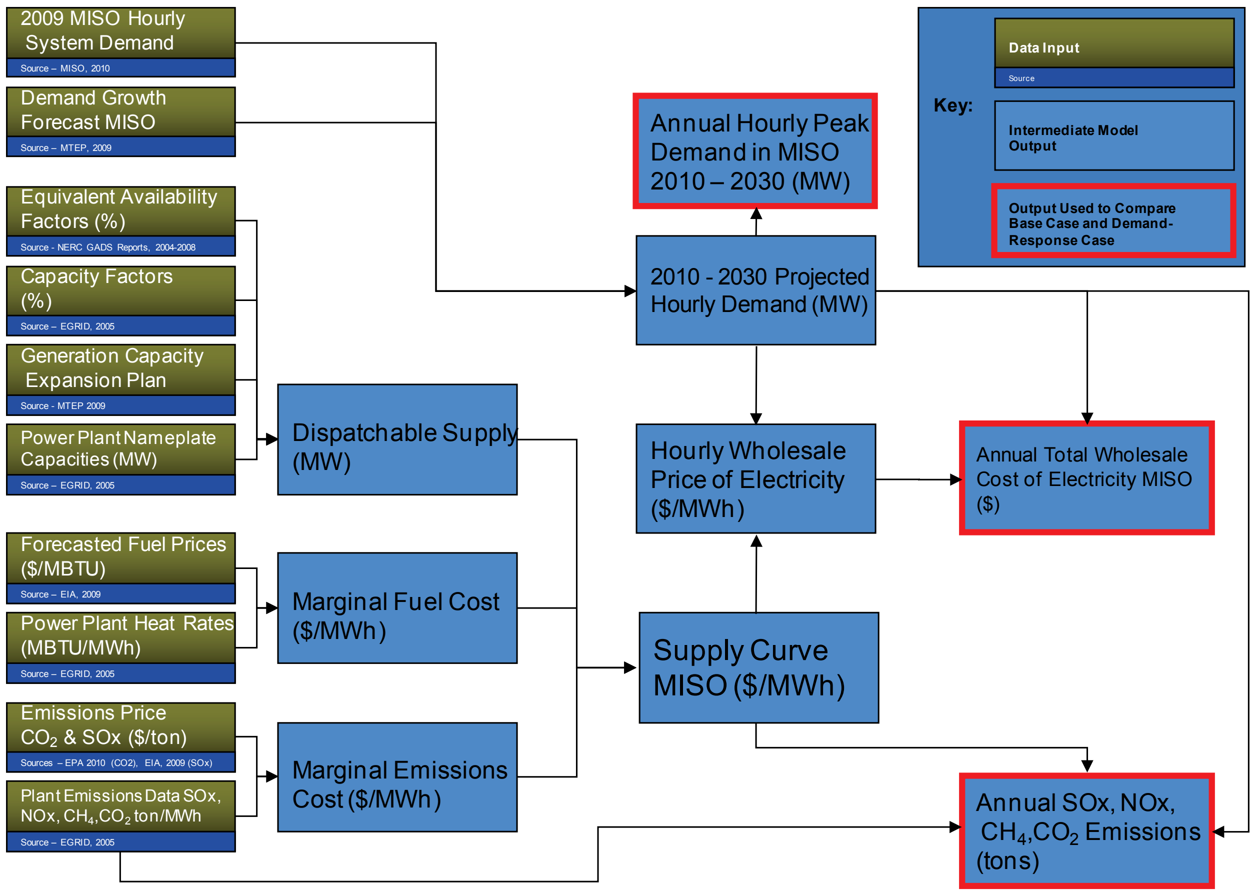


Figure 5 - Model Diagram of Base Case Analysis

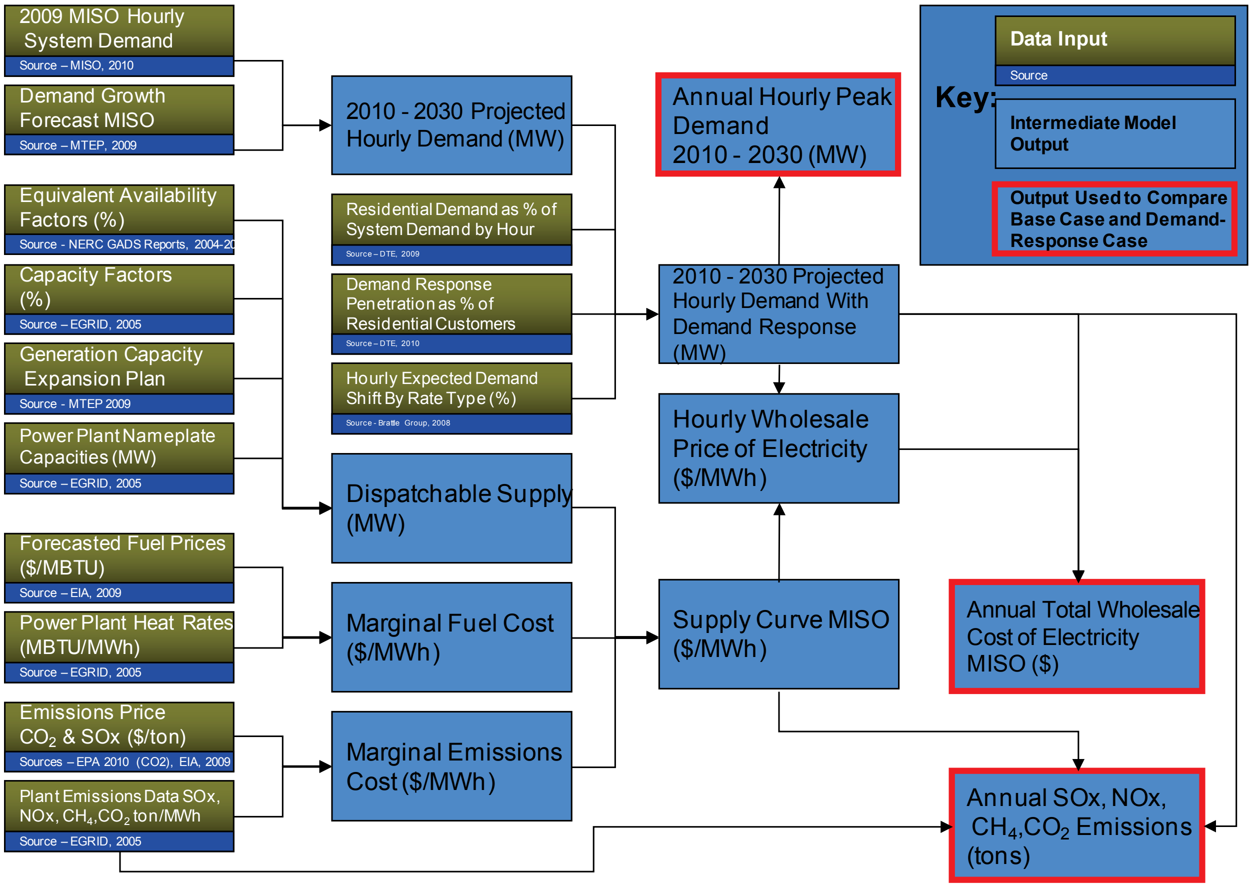


Figure 6 - Model Diagram of Demand Response Case Analysis

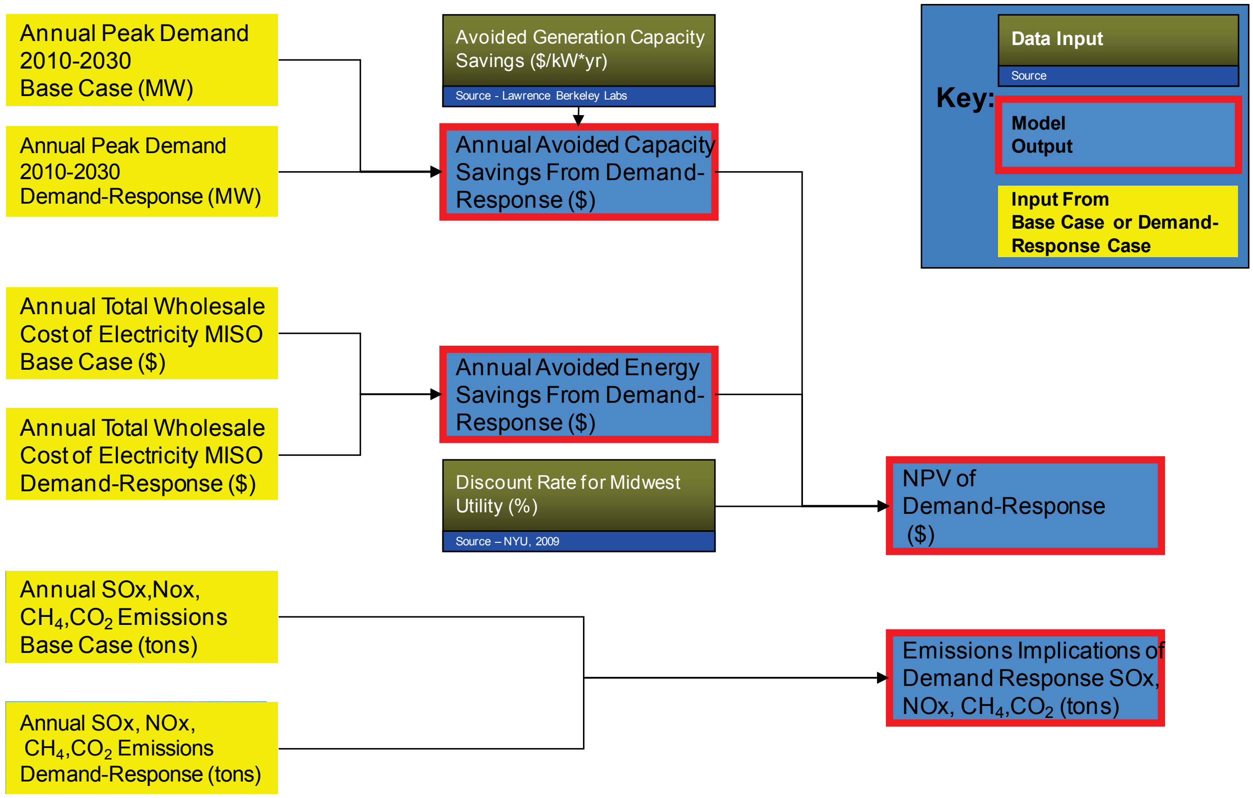


Figure 7 - Model Diagram Comparing Base Case and Demand Response Case

7.2.1 Data and Methodology

We collected data for all MISO power plants from the Emissions & Generation Resource Integrated Database (eGRID).[67] This data includes power plant name and location, nameplate capacity, capacity factor, fuel type, heat rate, and emissions levels. Power plant equivalent availability factors (EAFs) were taken from the North American Electric Reliability Corporation (NERC).[68] The EAF for a power plant adjusts that plant's available hours by taking into account things such as seasonal derated hours and planned derated hours.

Power plant fuel sources included nuclear, coal, natural gas, oil, hydro, landfill gas, wind, solar, and biomass. To calculate the marginal cost, or supply, curve within each ISO, we used the Energy Information Administration (EIA) Annual Energy Outlook 2010 Reference Case fuel price forecasts for coal (AEO 2010 Table 15), natural gas (AEO 2010 Table 13), and oil (AEO 2010 Table 12).[69] Data for other fuel sources was not needed because power plants with such fuel sources typically bid-in at $0 due to either the zero fuel cost or the high expense of operating below capacity.

7.2.2 *Calculating Supply*

The dispatch model uses supply and demand forecasts to calculate the wholesale price of electricity for each hour of each day from 2010-2030. To arrive at the marginal cost curve, we took the following steps.

1. We began with power plant nameplate capacity
2. Multiplied by
   a. the EAF for coal, nuclear, natural gas, municipal solid waste, biomass, landfill gas, and oil plants,[a] or
   b. the average of the 2004 and 2005 (the most recent years available) capacity factors for wind and hydro facilities from eGRID[70]
3. Multiplied by the forecast fuel price (converted into $/MWh), and
4. Added SO_2 costs ($/MWh) based on emissions levels for each plant (SO_2 prices are assumed to remain constant at recent price levels of approximately $200 per ton).

See sample calculation in Appendix D.

7.2.3 *Calculating Demand*

On the demand side, for baseline information, we used actual load data for the past 12 months from MISO and applied growth rates as projected by MISO to approximate a business-as-usual (BAU) scenario. [71,72] To estimate demand reduction that could occur as a result of various dynamic pricing programs, we assumed that dynamic pricing would only impact the portion of demand that is used by residential customers (since we assume that the dynamic pricing programs will focus on residential electric use). MISO load data is aggregated by total demand, including residential, commercial, and industrial customers. As a result, it is necessary to isolate the residential part of the load. To do this, historical average household load data for DTE customers was multiplied by the number of residential customers in the MISO service territory.[73] The resulting product (Residential Demand, or RD), subject to certain growth rates, yields the expected residential load for a given day and hour in future years.

7.2.4 *Calculating the Cost of Generation*

The cost of generation for any given hourly time period was calculated by estimating total demand in a given hour and then multiplying by the marginal cost of generation at that given level of demand. There are some important ways that our model differs from actual ISO dispatching. ISOs dispatch power plants based on locational marginal prices (LMPs);

---

[a] NERC does not publish EAFs for municipal solid waste (MSW), biomass, and landfill gas (LFG) facilities, so we used the EAF for natural gas as a proxy due to the fact that MSW, biomass, and LFG facilities are functionally similar to natural gas facilities.

buyers and sellers submit bids and offers for each hour of the day at various nodes throughout the transmission network. Sellers receive the market-clearing price, meaning that if the last generating unit needed to meet demand at a particular node in any given hour offered its electricity at $60 per MWh, all sellers would receive that price and all buyers would pay that price. Total costs for electricity at that specific time on that particular node would therefore be $60 multiplied by the total number of MWhs required to meet demand.[74] Because our model is designed to capture macro-level impacts of dynamic pricing programs (as opposed to calculating prices at various nodes on the grid), we match overall supply in MISO with overall demand in MISO to arrive at hourly market-clearing prices for MISO as a whole.

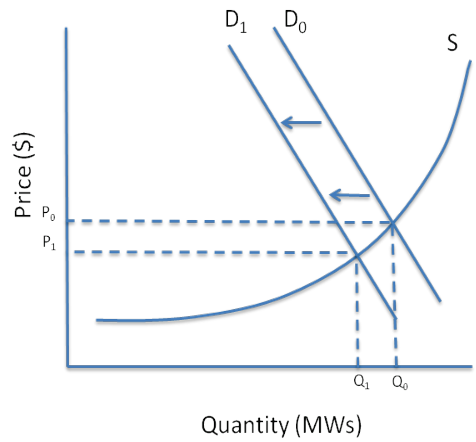


Figure 8 - Interaction of Supply and Demand

Figure 8 outlines the basic mechanics of supply and demand within an ISO service territory and how prices are set in a given hour. The hypothetical leftward shift in the demand curve demonstrates how a reduction in demand from dynamic pricing can lead to a lower market-clearing price (and lower total costs of electricity), given the shape of a typical electricity supply curve (labeled S below).

There are other aspects of the MISO markets that are not addressed in this paper; as an example, in MISO, there is a day-ahead energy market, a real-time energy market, and a financial transmission rights market (FTRs). Buyers and sellers meet on these markets, and MISO oversees the auction process while ensuring that energy supply is secure and reliable. The day-ahead market is the primary market on which load is scheduled. The real-time market serves to smooth any imbalances, with LMPs clearing every 5 minutes, and FTRs are mechanisms to hedge against transmission congestion.[75] Again, because the goal of our project is to identify macro-level impacts, we did not address these specific features of the MISO market in our model.

7.2.5 *Calculating the Savings Associated with Demand Response Programs*

The cost savings derived from demand response programs result from:

1) avoided energy costs
2) avoided generation capacity

In the simplest terms, the model calculates the energy produced under "normal," business-as-usual circumstances (i.e. with no demand response program) and the cost to the utility to procure that amount of electricity. It also calculates the projected energy produced under a demand response scenario. The difference between these two production estimates and their associated costs represents the potential savings associated with that demand response program.

Once the new demand levels are calculated by hour, total energy costs can be re-calculated. The difference between the total cost of energy before and after applying the various demand response scenarios represents potential energy savings from these programs.

Additional savings from pricing programs comes from avoided capacity costs. For instance, if a pricing program reduces the absolute peak demand, there is a savings associated with not needing as much standby capacity as would have been needed with a higher absolute peak. The cost of this capacity is assumed to be $80/kW-year, a proxy used by the Lawrence Berkeley National Laboratory to represent the carrying cost of a simple-cycle, natural gas peaking plant.[76]

In addition to avoided energy and avoided generation capacity, demand-response pricing will result in avoided transmission and distribution cost.[77] Due to the complexity of modeling transmission and distribution, our model does not look at avoided transmission and distribution costs. However, for reference, a study by the Brattle group found that avoided transmission and distribution costs accounted for 22% of the savings from dynamic pricing programs.[78]

7.3 Scenario Inputs

As discussed above, scenario inputs include level of demand-response pricing penetration, level of demand response (discussed in detail above), and presence of enabling technology. The sections that follow describe the specific scenarios that are used in the model.

7.3.1 Demand-Response Program Penetration

An important variable in determining the potential gains from residential demand response programs is the deployment rate of demand–response pricing programs. As discussed earlier, the rate of AMI deployment has been much slower than many people anticipated, and demand-response rate programs have touched just a small fraction of electricity customers. While recent federal support for smart meters and the growing acceptance of their benefits is likely to increase the rate of AMI deployment, there is still considerable uncertainty surrounding estimates of how quickly demand-response pricing will penetrate the residential electricity market.

In order to determine the effect of various demand-response pricing deployment schedules, our model uses three different scenarios. The "*medium*" scenario correlates with a deployment of demand-response pricing to one percent of households per year. This scenario is based on discussions with DTE and their expectation that demand-response pricing will be deployed to 10% of residential customers in ten years (by 2020). The "*low*" scenario deploys demand-response pricing to .5% (5% total by 2020) of residential customers per year and the "*high*" scenario to 2% (20% total by 2020) of households per year. In our model, these penetration rates increase through 2030, reaching 10%, 20%, and 40% for the low, medium, and high scenarios respectively.

7.3.2 *Generation Expansion*

Load and capacity in MISO are projected to expand over the modeled time period from 2010 to 2030, and the model assumes that capacity expands in line with various MISO forecasts. For the base-case generation capacity expansion we used a reference case from a transmission-planning document, which MISO considers a "status quo" scenario that takes into account, for example, existing legislation and RPS requirements.[79] This forecast is specific to the year 2024, so we expanded capacity of the various generation asset-types linearly to meet the 2024 forecast, and then continued to expand capacity at the same linear rate through 2030.

In addition to the reference generation expansion, MISO also forecasts generation expansion under a 20% RPS mandate as well as under a carbon tax scenario, called "environmental growth scenario." Using the same methodology as in the reference case, we model generation expansion under the 20% RPS mandate and the environmental growth scenario.

The model allows for analysis of demand response programs under any of the three capacity expansion scenarios.

7.3.3 *C*arbon Price

The model can incorporate a carbon price into the calculation of the marginal cost of generation for all generation plants in the supply stack. Using data from EGRID on CO_2 emissions per MWh for each generating facility in MISO and multiplying this by a forecasted carbon price we obtain a marginal cost per MWh of CO_2 emissions for each generating unit.[80] We use carbon price forecasts from the EPA's analysis of the American Clean. Energy Security Act of 2009.[81] All scenarios are run without a carbon price unless explicitly indicated.

7.3.4 *Program Type and Level of Demand Response*

7.3.4.1 Overview

The next step in the process is to calculate by how much the residential load will decrease as a result of the demand response program. Accurately forecasting how consumers will respond to a demand response program is a difficult task given all of the influencing variables. There are 2 key components that are needed to calculate overall demand response levels: 1) customer response levels in peak periods 2) amount of customer response that is shifted to off-peak periods (the remainder is assumed to be conservation).

7.3.4.2 Presence of enabling technology

One key piece of this analysis is that some of the program types incorporate enabling technology and others do not. To estimate the cost associated with those that do incorporate enabling technology, we contacted a number of well-known enabling technology vendors to get a range of prices for high volume purchases of enabling technologies by utility customers. Because prices are proprietary to these vendors, we obtained prices under Non-Disclosure Agreements. The estimated costs we received ranged from $300 to $500 for one time start-up costs and $25 - $35 for annual operating costs per residential customer. We used an average of these ranges in our model calculations, and we assumed costs do not decrease over time. The per customer start-up costs includes costs for an In-Home Display (IHD), IHD installation, a Programmable Communicating Thermostat (PCT), PCT installation, and an initial software fee. The per-customer operating costs included an annual software fee and a service fee. These costs are included in the modeling of all Program Types that incorporate enabling technology.

7.3.4.3 Customer Response Levels

There is significant empirical evidence that consumers will adjust their electricity usage in response to price changes. A compelling conclusion is that a wide variety of consumers exhibit price response when provided an opportunity to do so.[82] The relative tight bunching of elasticity estimates from a variety of dynamic pricing pilots, involving different customer segments under different market circumstances, suggests that price response impacts can be estimated quite confidently and accurately.[83] More specifically, 15 dynamic pricing experiments were examined yielding the results summarized in Table 1.[84]

Table 1 – Mean Residential Customer Response from Previous Demand-Response Pricing Pilots

Rate Design	Number of Observations	Mean	95% Lower Bound	95% Upper Bound	Min	Max
TOU	5	4%	3%	6%	2%	6%
TOU w/ Technology	4	26%	21%	30%	21%	32%
PTR	3	13%	8%	18%	9%	18%
CPP	8	17%	13%	20%	12%	25%
CPP w/ Technology	8	36%	27%	44%	16%	51%

.

It is important to understand that these results signify the peak period consumption reduction between the treatment and control group. Hence, assuming 1) the peak period was 2:00 pm – 6:00 pm 2) the rate design was a “CPP w/ Tech,” and 3) a critical event day was called, then if the control group consumed 10 kWh during this 4 hour window, the treatment group, on average, would consume 36% (3.6 kWh) less, or a total of 6.4 kWh.

However, changes in electricity consumption induced by a dynamic pricing rate design can vary based on numerous variables including:

1. Rate Design
2. Price elasticity of individual household (s)
3. Availability of and type of enabling technology
4. Ownership of central air conditioning and / or swimming pools
5. Type of days examined (weekdays vs. weekends).

6. Ratio of on-peak to off-peak and / or shoulder prices.
7. How often prices change,
8. Time of the day
9. Season of the year
10. Customer education initiatives
11. Amount of advanced notice of peak events and medium used to communicate peak event
12. Health of the economy in general
13. Availability of substitutes
14. Quantity and price thresholds
15. Weather
16. Income
17. Lifestyle
18. By definition, price response is not constant along a linear demand curve
19. Short Term vs. Long Term (allowing consumers to change their capital stock).[85]

7.3.4.4 Load Shifting and Conservation

There are several important dynamics to consider when estimating the electricity consumption changes associated with a dynamic pricing rate plan. One key dynamic is electricity conservation versus shifting. In a dynamic pricing rate plan, the customer experiences peak prices that are higher than previous peak prices and off-peak prices that are lower than previous off-peak prices. An increase in electricity price during the peak period can realistically induce one of four responses:

1. No change in consumption (perfectly inelastic)
2. Conservation – a reduction of overall electricity use (some level of own price elasticity)
3. Shifting – a reduction of electricity use during some time period (high price period), but that reduction is fully offset by an increase in electricity use during some other time period (low price period) indicating some level of substitution elasticity.
4. Both Conservation and Shifting

Understanding the relative levels of each of these four responses is important in assessing the value of dynamic pricing for the company and end consumer, and for the utility to properly plan demand response into its capacity and demand forecasts. The following example seeks to illustrate the importance of this dynamic. In Table 1 above, we see the range of the peak period consumption reduction in response to several different rate designs. These results reveal key information, but not the whole picture. These results tell us the % reduction during the peak period, but not what happens to the kWh reductions. Potentially, they are conserved and not consumed in another time period. For example, a light that is turned off during the peak period is not needed later in the day or evening. In effect, this energy was conserved because it was simply never used. If the energy is not conserved, it is simply shifted and consumed during another time period. For example, people delay running their dishwasher during the peak period and instead run it during the off peak period.

For a utility to best design least cost operation, it needs to understand how much electricity will be conserved at different price signals and how much electricity will be shifted. To take shifting one step further, the utility needs to understand exactly what time periods the reduced load will be shifted to. To better illustrate, assume there is a TOU / CPP with four rates: 1) a low off peak rate 2) a mid shoulder rate 3) a higher on peak rate 4) a very high critical peak rate. Table 1 tells us that, on average, we expect a 36% kWh demand reduction during the critical peak period (when an event has been called). If the control group consumed, on average, 10 kWh during the critical peak event, the treatment group, on average, consumed 36% less (6.4 kWh) during the same period. Table 1 specifically does not tell you if this reduction by the treatment group was "conserved" or "shifted" or both.

The utility wants to know how much of this reduced consumption is attributed to conservation (will not be consumed at some other time period) and how much is shifted (consumed during other time periods). Knowing this is not enough. They also want to be able to dissect the "shifted" portion of the load and know during what hours that reduced load will be shifted to within the off-peak or shoulder periods. Actually calculating the expected shift versus conservation and deriving when the shifted load would be consumed is difficult. Conservation vs. shifting as a concept is well understood, but the aforementioned calculations represent gaps in the literature.

7.3.4.5 Level of Demand Response Methodology (including Shifting and Conservation)

We used the results from the Brattle Group's study of empirical evidence from residential demand-response pricing, shown in Table 2, to determine peak and critical peak period consumption reduction for the corresponding rate design. We then used these results to project demand reduction using three scenarios ("high," "medium," and "low") for each of the different pricing structures analyzed; the goal was to generate a range of possible demand reductions. The "*medium*" scenario is the mean response seen in all previous studies, the "*high*" scenario is 20% greater than the mean expectation, and the "*low"* scenario is 20% less than the mean expectation. The demand response during critical peak events used in these scenarios is shown below in Table 2 while the demand response used in peak periods is shown in Table 3. These demand reductions during peak periods are applied uniformly across all hours of the peak period in the model.

Table 2 - Low, Medium, and High Demand Response Scenario Values during Critical Peak Periods

Program Type	Mean Reduction From Previous Pilots	High Scenario Response (+20%)	Low Scenario Response (-20%)
TOU	4%	5%	3%
TOU w/Technology	26%	31%	22%
PTR/TOU	13%	16%	11%
CPP/TOU	17%	20%	14%
CPP/TOU w/Technology	36%	43%	30%

**Positive values are reductions in demand*

Table 3- Low, Medium, and High Demand Response Scenario Values during Peak Periods

Program Type	Mean Reduction From Previous Pilots	High Scenario Response (+20%)	Low Scenario Response (-20%)
TOU	4%	5%	3%
TOU w/Technology	26%	31%	22%
PTR/TOU	4%	5%	3%
CPP/TOU	4%	5%	3%
CPP/TOU w/Technology	26%	31%	22%

To determine the portions of the peak load shifted to off-peak periods, we used the mean results of the change in off-peak consumption from previous pilots. Consolidated results of mean customer response during off-peak periods were not found in the literature, so we looked at the results of individual studies to estimate the off-peak demand response of residential customers.[b] This change in consumption was applied uniformly across off-peak hours (All hours outside of the peak period). This is an oversimplification of how consumers will actually respond, but is a reasonable assumption to use before empirical data is gathered from DTE's pilot studies. The off-peak response was manipulated to create a "low," "medium," and "high," demand response scenario using the same methodology described above for critical peak and peak time reductions. The final values for customer response during off-peak periods used in the model are shown below in Table 4 (note that these figures represent *increases* in electricity consumption, whereas the peak and critical peak figures in Table 2 and Table 3 above represent *decreases* in electricity consumption. The expected shift in off-peak consumption is something that is not well documented in the literature, and so we believe there is a high level of uncertainty surrounding these estimates.

Table 4 – Low, Medium, and High Demand Response Values during Off-Peak Periods

Program Type	Mean Response from Previous Pilots	High Demand Response (+20%)	Low Demand Response Scenario (-20%)
TOU	0.8%	0.90%	0.63%
TOU w/ Technology	3.0%	3.6%	2.4%
PTR	0.8%	0.90%	0.6%
CPP	0.8%	0.90%	0.6%
CPP w/ Technology	3.0%	3.6%	2.4%

[b] Off-Peak results based on the following studies: California ADRS, California Statewide Pricing Pilot, XCEL experimental residential price response program.

The underlying assumption behind the methodology of using the results of previous residential demand-response pricing pilots is that the key variables of the DTE pilot will be similar to previous pilots, thus DTE can expect similar demand response in their demand-response program. The benefit of this method is its relative simplicity; however, due to different characteristics of previous studies such as rate designs, demographics, and regional climate, it is likely that the DTE population will behave in a manner that is not identical to the mean results from previous studies. The high, medium, and low response rates are meant to address some of this uncertainty.

7.3.5 Alternate Demand Response Methodology

Toward the end of our project, an opportunity emerged for DTE to engage the Brattle Group to calculate customer demand response levels tailored to DTE's service territory. Because we recognized the potential for improved accuracy associated with the Brattle Group's methodology, as compared to using mean demand response levels from previous pilots, we pursued this opportunity. Timing did not allow for us to perform as much analysis utilizing the Brattle Group data as we performed utilizing the mean response data outlined in Section 7.3.4. However, we were able to conduct a preliminary analysis of the Brattle Group data and found that customer demand response levels appear substantially lower than those that we modeled. A discussion of these findings and results can be found in Appendix F - PRISM Model Simulations, Appendix G –Tariffs and Expected Demand Reductions Using Prism Simulation, and Appendix H – Financial Modeling Results of Selected Tariffs from PRISM Simulation.

7.3.6 Modeled Scenarios

Based on the inputs described in Sections 7.3.1 – 7.3.4, we ran the following scenarios to arrive at the results described in Section 8 below:

1) TOU, Medium Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
2) TOU/Tech, Medium Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
3) TOU/CPP, Medium Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
4) TOU/CPP/Tech, Medium Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
5) CPP/TOU/Tech, Low Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
6) CPP/TOU/Tech, High Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
7) TOU/Tech, Low Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
8) TOU/Tech, High Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price

9) TOU/Tech, Medium Demand Response, Medium DR Penetration, 20% RPS Mandate, No Carbon Price
10) TOU/CPP, Medium Demand Response, Medium DR Penetration, 20% RPS Mandate, No Carbon Price
11) TOU/CPP/Tech, Medium Demand Response, Low DR Penetration, Base Case Generation Growth, No Carbon Price
12) TOU/CPP/Tech, Medium Demand Response, High DR Penetration, Base Case Generation Growth, No Carbon Price
13) TOU/PTR, Medium Demand Response, Medium DR Penetration, Base Case Generation Growth, No Carbon Price
14) CPP/TOU/Tech, Medium Demand Response, Medium DR Penetration, 20% RPS Mandate, No Carbon Price
15) TOU/Tech, Medium Demand Response, Medium DR Penetration, Environmental Growth Scenario, Carbon Tax
16) TOU/CPP/Tech - Medium Demand Response, Medium DR Penetration, Environmental Growth Scenario, Carbon Tax

The Program Type (CPP, TOU/Tech, etc.) dictates which demand response levels we utilize for modeling purposes. As an example, for TOU/Tech with Medium Demand Response levels, we use the values listed in Table 2, Table 3, and Table 4 under TOU/Tech Mean Scenario. For TOU/Tech under High Demand Response, we use information from the same tables listed under TOU/Tech High Scenario.

7.4 Additional Data - Defining Peak Periods and Event Days for the Model

The peak period under a demand response pricing tariff should be large enough to ensure that it captures all of the peak demand hours during a year, but not so long that it inhibits customer response to the increased tariff. As Ahmad Faruqui states "The on-peak or critical peak periods should be kept as short as is possible while still reasonably spanning the period during which the system peak occurs. A shorter peak period makes it easier for customers to shift load to the off peak period when demand reductions are not as critical."[86]

Figure 9 below shows the load profile within MISO for the 5 highest demand days in 2009. As can be seen in the figure, the absolute annual peak demand level occurs during the hour ending at 2:00 pm (hour 14) on June 25 and at 4:00 pm (hour 16) on June 24. In order to span this range during which the peak event may occur, we have designated the peak period to cover the hours of 1:00 pm to 5:00 pm in most of the demand-response pricing programs modeled.

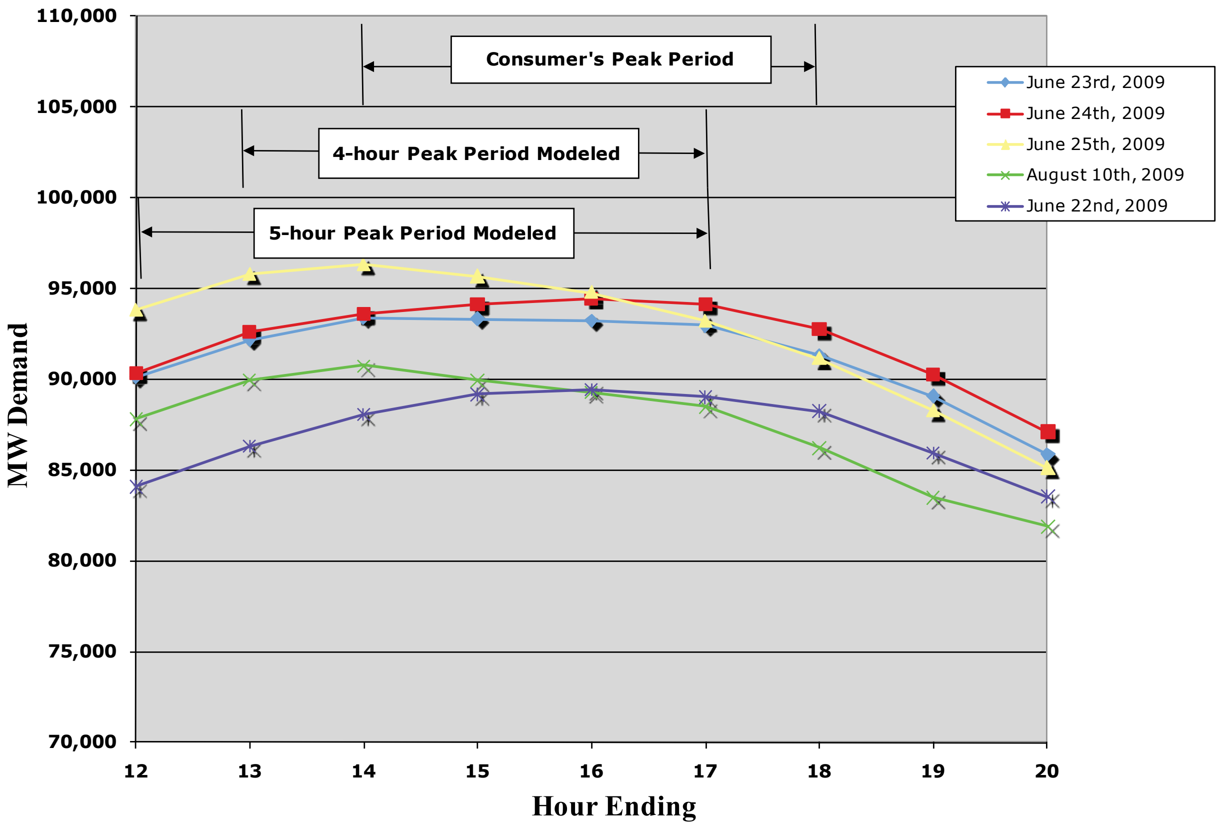


Figure 9 - Load Profiles for Five Highest Demand Days of 2009 in MISO and Peak Period Designations

In addition to the designation of the peak period, CPP and PTR programs typically have a maximum number of event days that may be called. During these event days, electricity in the peak period will be priced at the CPP rate, or customers will be given rebates under a PTR program. A review of previous demand-response pilots found that a maximum of 8-10 event days was typical. Our model designates the ten highest demand days during the summer in each year as critical event days. Table 5 shows the ten days that are designated as critical event days, the corresponding peak load, and the time (hour ending) during which the peak load was observed in 2009 in MISO.

Table 5 - Peak Demand Days in MISO 2009

Date	Peak Demand (MW)	Hour Ending of Peak Load
June 25, 2009	96,326	14:00
June 24, 2009	94,456	16:00
June 23, 2009	93,396	14:00
August 10, 2009	90,763	14:00
June 22, 2009	89,459	16:00
June 26, 2009	88,949	16:00
August 14, 2009	88,449	16:00
August 17, 2009	87,538	14:00
August 11, 2009	86,189	15:00
August 13, 2009	85,627	16:00

8 Results

8.1 Overview

Using the dispatch model described in the previous section, we analyzed demand response scenarios 1-16 (listed above in Section 7.3.6) within MISO. Each demand response scenario was compared to a Business as Usual (BAU) scenario; in the BAU scenario, each element of the scenario remains the same except for the fact that there is no demand response program in place. As an example, in Scenario 16 (listed in Section 7.3.6), the BAU scenario calculates energy costs and capacity needs under an Environmental Growth and Carbon Tax Scenario (the other components of that scenario all relate to demand response programs, hence they are not included in the BAU scenario). The model then calculates energy and capacity savings (see Section 7.2.5 above) associated with adding the demand response elements to that scenario (i.e. that the program type is TOU/CPP/Tech, that the demand response level is medium, and that there is medium DR penetration).

The results from the modeling provide the total cost savings for the MISO system. DTE comprises approximately 20% of the MISO system, and so the impact to DTE will be approximately 20% of the savings and cost of deploying demand-response pricing estimated by the modeling exercise.

At a high level, deployment of demand response programs under the base-case assumptions detailed in the Section 8.2 result in financial outcomes ranging from a net loss of \$350 million for a TOU tariff with technology to a net gain of \$400 million for a CPP/TOU tariff without technology. \$400 million represents a savings of less than 0.25% of total wholesale electricity costs from 2010-2030 and of less than 1% of the residential portion of total wholesale electricity costs from 2010-2030. Our modeling, however, shows that increasing the peak period window length to five hours significantly increases the value of demand response programs, especially those with enabling technology. Using a five-hour event window, financial outcomes range from a net loss of \$50 million for a TOU with technology to a net gain of \$450 million for a CPP/TOU program. A CPP/TOU with technology tariff using a five-hour event window results in net benefits of \$210 million. If the event window lengths are increased to eight hours, net benefits increase further, ranging from \$419 million for a PTR program to \$557 million for a CPP/TOU with technology program. The benefits of a tariff with an eight-hour window, however, may be overstated as customers' ability to maintain demand reduction for such a long time period may be limited. A summary of the results from scenarios associated with various peak hour windows can be found in Appendix E. Note that aside from the differences in peak hour window lengths, these scenarios use base-case assumptions detailed in the Section 8.2 below.

As might be expected, changes in the levels of deployment of dynamic pricing programs as well as changes in the levels of customer demand response have significant impact on the overall cost savings. Other notable results from the modeling exercise include that emissions levels are not significantly impacted by demand response programs, and that a large deployment of wind within MISO has little overall impact on the savings associated with demand response programs.

8.2 Comparing Programs under Base Case Assumptions

Our initial analysis looked at the five different demand response pricing programs under base-case assumptions. The results of this exercise show that TOU with enabling technology and TOU/CPP with enabling technology will result in the largest cost savings for DTE resulting in a cost reduction of approximately 0.30%. However, if DTE must bear the cost of enabling technology, the cost savings of these programs are actually negative (i.e. a financial loss), changing to -0.14% of total energy cost. This indicates that the enabling technology providers may be capturing most of the financial gain from deployment of enabling technology and DTE should thus use caution in estimating its financial gains due to enabling technology deployment and also in negotiating prices. Additionally, DTE should strongly consider the option of rate-basing enabling technology, or having customers contribute to the cost if it wishes to proceed with deployment of enabling technology.

The assumptions used in our base-case modeling include the following:

1) Medium demand response penetration (see Section 7.3.1)
2) Mean demand response levels reported in previous programs (see Section 7.3.4)
3) Base-case generation forecasts from MISO (see Section 7.3.2)[87]
4) No carbon tax (see Section 7.3.3)
5) 5% Cost of Capital (this assumption is held constant throughout all scenarios)
6) 4-hour peak period from 1:00 pm – 5:00 pm (See Section 7.4)
7) 10 Critical event days for CPP and PTR tariffs (See Section 7.4)

Table 6 lists the results of this initial analysis. The results indicate that TOU with technology and TOU/CPP with technology offer the largest potential cost savings for MISO and DTE. However, this savings is more than offset by the cost of deploying enabling technology.

Table 6 - NPV of Cost Savings of Various Demand Response Pricing Tariffs in MISO

Program Type	Avoided Energy (in Millions)	Avoided Capacity (in Millions)	NPV Cost Savings (in Millions)	Technology Cost (in Millions)	Net NPV (in Millions)	Cost Reduction (% of Total Electricity Cost)	Cost Reduction (% of Residential Electricity Cost)
TOU	$11	$94	$105	$ -	$105	0.05%	0.20%
TOU/PTR	$50	$300	$350	$ -	$350	0.16%	0.66%
TOU/CPP	$39	$360	$399	$ -	$399	0.19%	0.75%
TOU w/Tech	$174	$399	$573	($925)	($352)	-0.17%	-0.66%
TOU/CPP w/Tech	$195	$439	$633	($925)	($292)	-0.14%	-0.55%

As mentioned above, DTE comprises approximately 20% of MISO, and applying this percentage to the cost savings within all of MISO provides an estimate of the cost savings that DTE will realize by deploying demand-response pricing. Table 7 shows the cost savings for DTE.

Table 7 - Cost Savings to DTE from Demand Response

Program Type	Avoided Energy (in Millions)	Avoided Capacity (in Millions)	NPV Cost Savings (in Millions)	Technology Cost (in Millions)	Net NPV (in Millions)	% Cost Reduction	Cost Reduction (% of Residential Electricity Cost)
TOU	$2.2	$18.8	$21.0	$0.0	$21.0	0.05%	0.20%
TOU/PTR	$10.0	$60.0	$70.0	$0.0	$70.0	0.16%	0.66%
TOU/CPP	$7.8	$72.1	$79.9	$0.0	$79.9	0.19%	0.75%
TOU w/Tech	$34.8	$79.7	$114.5	($185.0)	($70.5)	-0.17%	-0.66%
TOU/CPP w/Tech	$38.9	$87.7	$126.7	($185.0)	($58.4)	-0.14%	-0.55%

Table 8 shows the distribution of cost savings between avoided energy savings and avoided capacity savings under the base case scenarios. Of particular note is that TOU with technology and CPP/TOU with technology tariffs result in a higher percentage of savings from avoided energy. The reason for this is that with a four-hour peak period and the high demand response rate of consumers under these rate plans, the hours adjacent to the 1:00 pm – 5:00 pm peak window end up with higher demand than what used to be the peak hour of demand (See Figure 10 below). Once demand in the hours adjacent to the peak window surpasses demand in the event window, annual avoided capacity savings will no longer increase, but avoided energy savings continue to grow.

Table 8 - Distribution of Cost Savings in Base Case Scenarios

Program Type	Avoided Energy	Avoided Capacity	NPV Cost Savings
TOU	11%	89%	100%
TOU/PTR	14%	86%	100%
TOU/CPP	10%	90%	100%
TOU w/Tech	30%	70%	100%
TOU/CPP w/Tech	31%	69%	100%
Average	19%	81%	100%

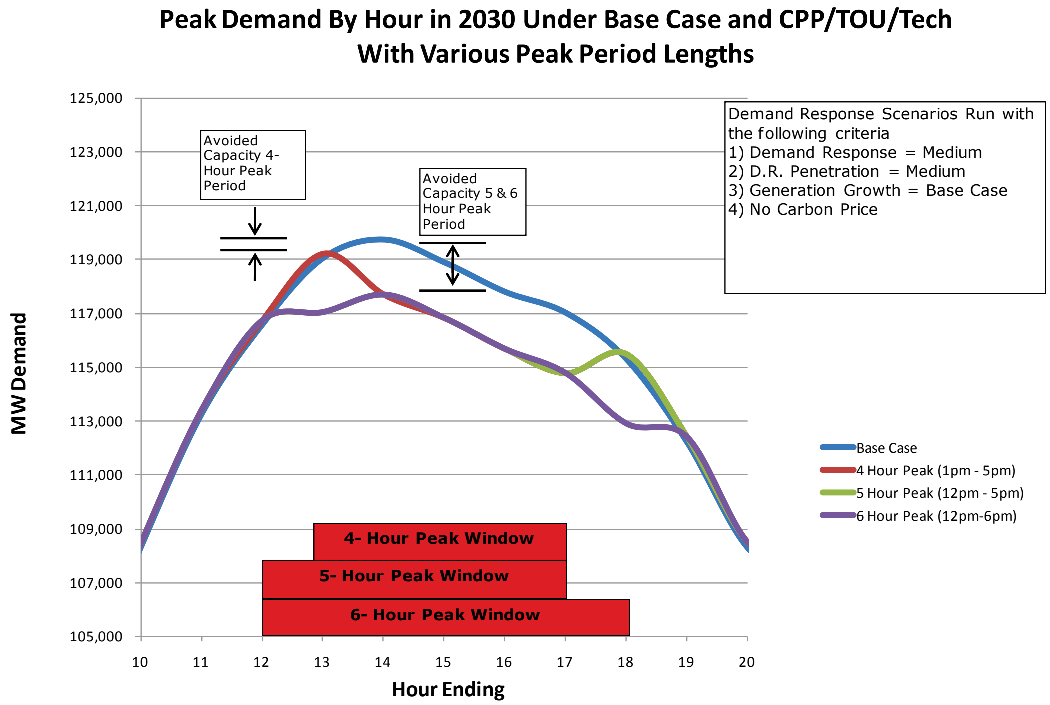


Figure 10 - Modeled avoided capacity savings using 4, 5, and 6 hour peak event window in 2030 with CPP/TOU w/ tech

8.3 Changing the rate of demand-response penetration

One of the central goals of our analysis was to identify the effect of changing the penetration rate of demand-response programs. In particular, we were interested in whether the cost savings from demand response will continue to grow in a linear fashion, for reasonable levels of demand-response penetration, or if there are diminishing or exponential returns. Based on our analysis, the gains from avoided energy continue to grow in an almost linear fashion for levels of demand response penetration up to double the base case levels (e.g. 2% of residential customers in 2010, 4% in 2011, increasing to 40% by 2030). However, using a 4-hour peak period, there are diminishing avoided capacity gains with more demand response penetration for the programs with high levels of customer response. As described in the previous section, in the deployment of a CPP/TOU with technology program, the hours adjacent to the 1:00 pm - 5:00 pm window become the peak hours once a sufficient number of customers are enrolled in demand-response pricing. Once this occurs, annual avoided capacity savings are very limited and in fact will be diminished with further deployment of demand-response pricing because further demand-response pricing will further increase peak demand in the time periods adjacent to 1:00 pm – 5:00pm.

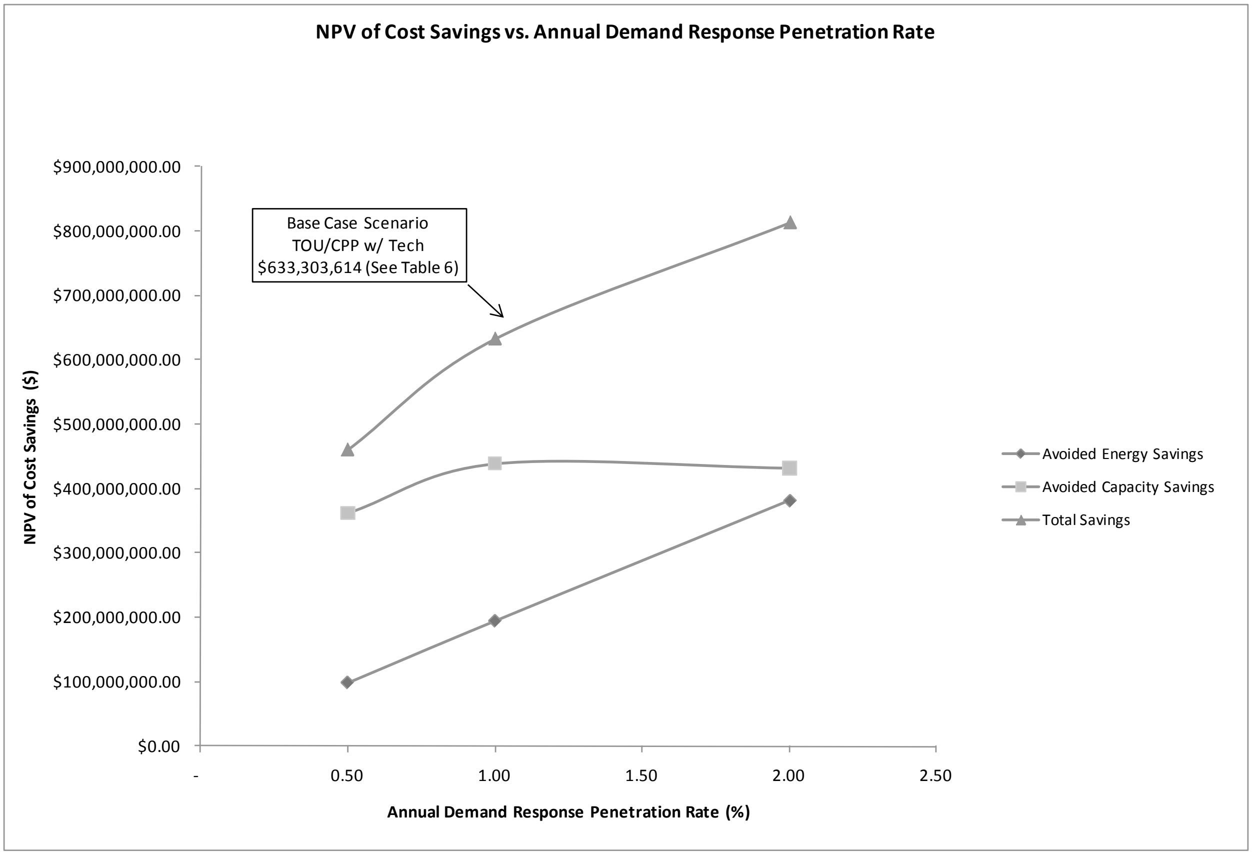


Figure 11 - NPV of Cost Savings of CPP/TOU w/ Tech vs. Annual Demand Response Penetration Rate

8.4 Level of Demand Response

In previous demand-response pricing pilots, there has been a wide range of observed responses by customers. Until DTE obtains data from its initial pilots, there will be significant uncertainty surrounding the level of demand response that will be realized. This section of the analysis looks at the sensitivity of the financial gains of demand response pricing to the level of demand response of customers. Under these scenarios, “medium” demand response is the mean level of response seen in previous studies. “Low” is a 20% reduction in response from the “medium” scenario, and “high” is a 20% increase in response from the “medium” scenario.

Table 9 - NPV of Cost Savings under Low, Medium, and High Demand-Response Scenarios

Program		Low Demand Response	Medium Demand Response	High Demand Response
TOU/CPP/Tech				
	Avoided Energy	$156,000,000	$195,000,000	$232,600,000
	Avoided Capacity	$424,000,000	$439,000,000	$445,200,000
	Total	**$580,000,000**	**$634,000,000**	**$677,800,000**
CPP/Tech				
	Avoided Energy	$139,000,000	$174,000,000	$208,000,000
	Avoided Capacity	$375,000,000	$399,000,000	$411,000,000
	Total	**$514,000,000**	**$573,000,000**	**$619,000,000**

The results of this modeling exercise indicate that the financial returns to demand response pricing are highly sensitive to the level of demand response (see Table 9). While predictions can be made using the price elasticities of DTE's customer base, wide variations of responses in previous studies indicate that this may be a challenging exercise. Given the sensitivity of the cost savings to the level of demand response, DTE should use the pilot pricing programs to collect detailed information about how customers respond to the new tariff structures. This should include a thorough analysis of own-price elasticity and the elasticities of substitution between all hours of the day. Only through empirical analysis of its specific customer set can DTE be fully confident in how its residential customers will respond to dynamic pricing programs. The results from the Brattle Group analysis for example (discussed in Appendix F - PRISM Model Simulations, Appendix G –Tariffs and Expected Demand Reductions Using Prism Simulation, and Appendix H – Financial Modeling Results of Selected Tariffs from PRISM Simulation) indicate that customer response rates within DTE's service territory may be significantly lower than the response rates modeled to arrive at the results found in Table 9. Of course, this has a significant impact on the NPV of savings, as is outlined in Appendix H.

8.5 Pollution Implications of Demand Response Pricing

One of the questions surrounding demand response pricing programs is whether such a program will increase or decrease emissions. This is of particular concern in a market like MISO in which base-load power is supplied by coal generation facilities while peak demand periods may be served by natural gas generation facilities (as discussed below, within MISO, peak demand periods may be served by coal facilities as well). Thus, shifting a portion of peak demand from peak to off-peak periods may actually increase emissions by substituting electricity from a natural gas generation unit for electricity from a coal generation unit.

The results in Table 11 below illustrate the impact of demand-response pricing on emissions within MISO from 2010 - 2030. As can be seen in the table, demand response may actually decrease emissions within MISO. This result is likely due to the fact that for the majority of days, peak demand is actually served by coal generation facilities. This result from the model is supported by FERC's classification of coal as the marginal fuel type within MISO.[88] Thus shifting electricity consumption from peak to off-peak periods is actually shifting generation to a more efficient, relatively cleaner coal facility. This effect, coupled with pricing-induced conservation from demand response, appears to offset the increase in pollution from demand response on those days when peak load is served by natural gas generation.

Table 10 - Pollution Implications of Demand Response Tariffs under Base-Case Scenarios

Program Type	**Pollutant**	*Base Case (Tons)*	*Demand Response Case (Tons)*	***Percent Change***
CPP/TOU/Tech				
	CO_2	10,441,007,000	10,432,785,000	-0.08%
	NO_x	16,510,000	16,498,000	-0.07%
	SO_x	48,899,000	48,868,000	-0.06%
	CH_4	220,000	220,000	0.00%
TOU/Tech				
	CO_2	10,441,007,000	10,433,050,000	-0.08%
	NO_x	16,510,000	16,498,000	-0.07%
	SO_x	48,899,000	48,870,000	-0.06%
	CH_4	220,000	219,800	-0.09%
TOU/CPP				
	CO_2	10,441,007,000	10,440,417,000	-0.01%
	NO_x	16,510,000	16,509,000	-0.01%
	SO_x	48,899,000	48,897,000	0.00%
	CH_4	219,900	219,900	0.00%
TOU/PTR				
	CO_2	10,441,007,000	10,439,660,000	-0.01%
	NO_x	16,510,000	16,508,000	-0.01%
	SO_x	48,899,000	48,894,000	-0.01%
	CH_4	219,900	219,900	0.00%

Although our modeling shows emissions reductions of up to .08%, there are several factors that may affect whether this result is stable. In particular, the level of demand on the MISO system in the future as well as the actual observed shifting of residential customers within MISO will impact these results. Given the depressed level of demand in MISO due to the economic downturn, only a small subset of hours is served by natural gas generation facilities. If demand were to rebound, demand response pricing may begin to shift generation more frequently from relatively clean natural gas facilities to dirtier coal generation facilities, reversing the pollution implications in our model. Additionally, if DTE's customers respond very differently to demand-response pricing compared to the results seen in past pilots, there may be a significant impact on the pollution implications of these programs.

Despite these variables, demand response may play a small role in emissions reductions for DTE. Although .08% emissions reduction may not seem significant, it is important to note that these emissions reductions result from deploying dynamic-pricing to just a subset of *residential* customers, meaning the vast majority of residential customers as well as all commercial and industrial customers are not subject to dynamic pricing. Because residential demand comprise approximately 25% of total demand in MISO, residential demand response pricing is influencing just 5% of total system load in the year 2030 under this modeling scenario. When considered from this perspective, the emissions reductions from residential demand response pricing are not insignificant and may warrant more aggressive deployment of demand-response pricing within MISO. However, overall impact on emissions is small and demand response pricing should not be considered a substitute for mechanisms that directly target emissions such as a carbon tax.

8.6 Impact of a 20% RPS Mandate

The electricity industry is highly dependent on policy mandates, and Renewable Portfolio Standards are certain to influence generation expansion within MISO. Using the MTEP planning forecasts discussed above (Section 7.3.2), we modeled the effect of generation expansion under a 20% RPS mandate and the resulting implications on demand response pricing programs.[89]

The addition of wind resources to meet the 20% RPS standard has the effect of shifting the supply curve to the right. Figure 13 shows the modeled supply curve under the base case scenario and under the 20% RPS scenario.

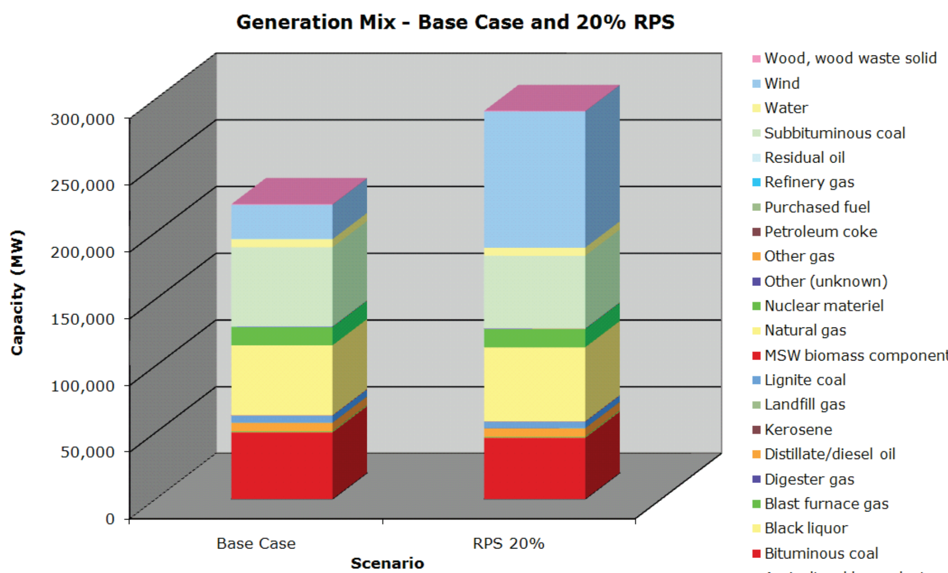


Figure 12 - Generation Mix in 2030 under Base Case and 20% RPS Scenarios

Table 11 shows the comparison of the financial returns to various demand response pricing programs under the base-case generation growth scenario and a 20% RPS mandate. The results indicate that savings from residential demand response programs are not highly sensitive to whether a renewable portfolio standard within MISO shapes future generation capacity expansion. The reason that savings is not highly sensitive to this shift is that demand rarely approaches the steep, expensive part of the supply curve within MISO. Because demand does not often hit the steep portion of the supply curve, there is little impact from shifting the supply curve to the right. Hence, there is not a significant impact on overall savings.

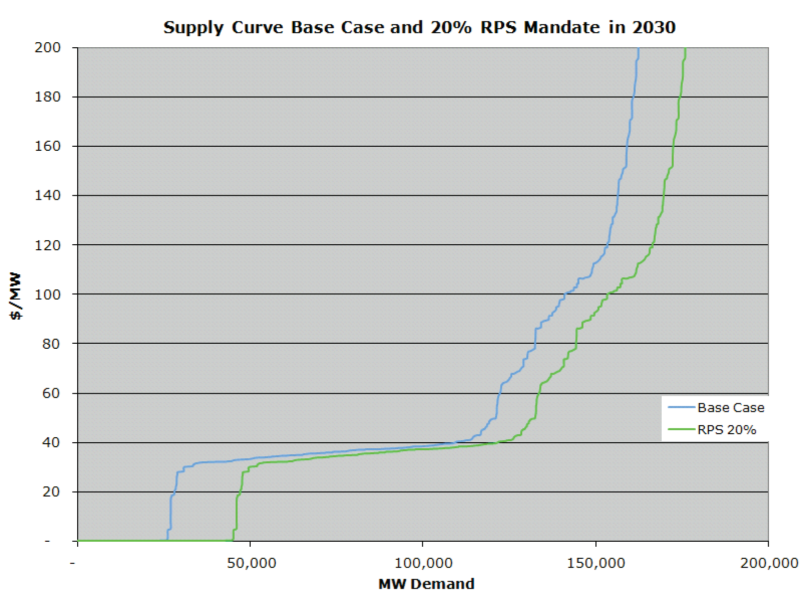


Figure 13 - Forecasted Supply Curve in MISO Under Base Case and 20% RPS Scenarios

Table 11 - NPV of Cost Savings under Base Case and 20% RPS Scenarios

Program Type	Savings	NPV of Savings Under Base Case	NPV of Savings Under 20% RPS
TOU/CPP w/ Tech			
	Avoided Energy	$195,000,000.00	$200,000,000
	Avoided Capacity	$439,000,000	$439,000,000
	Total	$633,000,000	$639,000,000
TOU w/ Tech			
	Avoided Energy	$174,000,000	$180,000,000
	Avoided Capacity	$399,000,000	$399,000,000
	Total	$573,000,000	$578,000,000

One shortfall of the model is that it uses a constant value of $80 per kW-yr as the cost savings from avoided capacity. This is why the 20% RPS mandate has no impact on the avoided capacity savings as modeled. It is possible that the generation expansion under the 20% RPS scenario may affect the cost of generation capacity, but this is beyond the scope of this project.

8.7 Effect of a Carbon Tax

Another policy that will have significant effect on the electricity industry is a carbon tax. In order to determine the impact of a carbon tax, we used the generation growth forecast under an environmental scenario in the MTEP planning forecasts and applied carbon price forecasts from the Environmental Protection Agency.[90] A carbon tax will increase the cost of carbon-based electricity generation and reduce the cost difference between coal and natural gas (See Figure 14). Due to the reduced spread between coal and natural gas costs under a carbon tax, we hypothesized that this would reduce the benefit of demand response pricing by reducing the cost differential between peak and off-peak electricity. However, our results indicate that the carbon tax actually increases the financial impact of demand-response pricing (See Table 12).

These results indicate that because coal is typically the marginal plant in MISO, the carbon tax actually magnifies the financial gains from demand-response pricing by making the supply curve steeper. This increase in financial impact more than offsets the reduction in financial gain (due to the reduced spread in cost between coal and natural gas) when natural gas plants serve peak load.

Table 12 - NPV of Cost Savings under Carbon Price Scenario

Program Type	Savings	NPV of Savings Under Base Case	NPV of Savings Under Carbon Price
TOU/CPP w/ Technology			
	Avoided Energy	$182,000,000.00	$287,000,000
	Avoided Capacity	$424,000,000	$424,000,000
	Total	**$606,000,000**	**$711,000,000**
TOU w/ Technology			
	Avoided Energy	$162,000,000	$267,000,000
	Avoided Capacity	$384,000,000	$384,000,000
	Total	**$546,000,000**	**$651,000,000**

Once again, our model uses a standard value of avoided capacity savings of $80 per kW-yr and thus avoided capacity savings are not impacted by the presence of a carbon price. In reality, a price on carbon may have an impact on the cost of generation capacity, but this is outside the scope of this analysis.

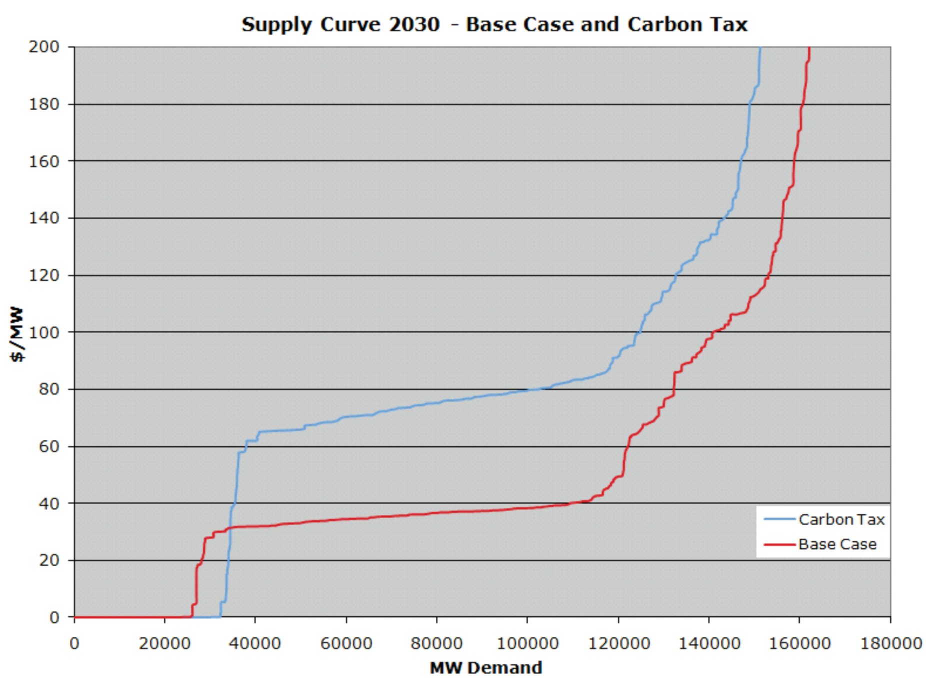


Figure 14 - Forecasted MISO Supply Curve in 2030 Under Base Case and Carbon Price Scenarios

9 Conclusions and Recommendations

9.1 Summary

This project's original goal was to provide DTE with specific demand response tariffs, prices, and corresponding expected net economic benefits from wide scale deployment. To accomplish this, we used the results of previous demand response pricing programs to identify the tariff structures that appeared most suitable for wide-scale deployment within MISO. We selected programs that had been piloted several times and had shown to effectively reduce peak period electricity demand. The pricing structures selected for in-depth research and simulation within our constructed dispatch model were TOU and TOU/CPP, with and without the presence of enabling technology (i.e. programmable communicating thermostat or in-home display) and TOU/PTR. Using the mean demand reductions exhibited by customers who faced these demand response tariffs in previous pilots, we simulated the potential financial and emissions implications of deployment of demand-response tariffs in MISO using a dispatch model of the independent system operator.

Additionally, through our investigation of the key attributes of successful demand response programs, we created several ideas for new types or permutations of demand response tariffs. The key findings of our analysis follow.

9.2 Key Findings

1. **Combined TOU and CPP programs with or without enabling technology provide the greatest demand response in the residential electricity market.** Based on our comprehensive review of past pilots from around the world, we found that TOU/CPP programs with or without enabling technology consistently outperform all of the other dynamic pricing tariffs that have been piloted. Not only does this program lead to demand shifts from peak to off-peak, but also offers consistent conservation and net reduction in energy use. Further, this combined tariff structure performs well with or without the use of enabling technology, though the response is better with the use of enabling technology.
2. **Enabling technology, specifically the programmable communicating thermostat and in-home display, substantially improves customer demand response. However, the cost of hardware, software and ongoing maintenance of the enabling technology appears to be greater than the NPV of the additional savings associated with using the enabling technology.** As noted in all of the previous pilots, enabling technology does greatly improve the overall impacts of demand response and significantly increases the savings in both avoided capacity and avoided electricity for the utility. However, the high price tag of enabling technology, including the in-home unit and ongoing operational costs, more than offsets these savings. As a result, the investment by the utility in enabling technology does not yield a positive NPV project. Instead, dynamic pricing tariffs that produce the most effective demand response without the use of

enabling technology will provide the highest economic benefit. However, if a utility is able to incorporate the cost of the enabling technology into the rate base or somehow have customers contribute to the costs of the enabling technology, then enabling technology could be very valuable.

3. **Costs savings to the utility are dominated by avoided capacity savings.** Our model totaled the savings to the utility for each demand response program. For simplicity, we limited those savings to avoided capacity and avoided energy costs. The results show that in every dynamic pricing tariff, the avoided capacity savings significantly outweigh the savings from avoided energy costs.
4. **The length of the CPP window is an important driver in overall cost savings.** Depending on a utility's service territory, peak demand can occur at different times of the day. Simulations suggest that short CPP windows, such as four hours, do not provide sufficient room to guarantee that peak demand will occur within this window. Furthermore, short windows may cause peak demand to occur in the periods adjacent to the CPP window, which virtually eliminates all of the avoided capacity savings that are achieved with longer CPP windows of 5 or 6 hours.
5. **The financial gains from the deployment of residential demand response using a four-hour peak window represent, at most, approximately 0.25% of the total cost of wholesale electricity from 2010-2030 and approximately 1% of the residential portion of wholesale electricity costs.** While there is some variation in savings based on changing the mix of variables in the scenarios we discussed, all scenarios yielded savings that were well under 1% of total energy costs. One potential reason for the limited savings is that the MISO area has experienced significant economic hardships since 2009. This along with other factors has contributed to an overall reduction both in peak demand and in the amount of time throughout the year that MISO approaches the very steep parts of the supply curve, times during which demand response efforts likely yield the biggest savings.

It is important to note that changes in the length of the peak window, as outlined in Appendix E, and substantial differences in the level of demand response, such as that observed in the Brattle Group data (outlined in Appendix F - PRISM Model Simulations, Appendix G –Tariffs and Expected Demand Reductions Using Prism Simulation, and Appendix H – Financial Modeling Results of Selected Tariffs from PRISM Simulation), has a significant impact on overall NPV.

9.3 Recommendations

The analysis in this paper demonstrates the potential outcomes of implementation of various demand response programs within MISO and DTE. There are many ways in which this research can be expanded to improve the granularity of this analysis. In addition, several recommendations can be made to DTE based on our modeling of the various tariff structures.

1. **DTE should run ProMod with the demand response tariffs and their corresponding estimated reductions that produced the greatest economic benefits.** While we are confident that our results provide a useful estimate of the potential range of economic impacts from dynamic pricing programs, it would be helpful to compare those results to those from a more sophisticated model such as ProMod. We did not have access to such a model, but our scenario assumptions could be used in ProMod to provide an additional level of certainty that addresses the simplifications highlighted below.
    a. In our model, wind generation and hydroelectric facilities generate power uniformly throughout the day. In reality, wind typically generates more electricity at night and less electricity during the day. Adding this temporal aspect of wind generation may improve the accuracy of the dispatch model. In addition, pumped-storage hydroelectric facilities are dispatched to maximize their economic value and are more likely deployed during periods of peak demand. Adding a mechanism to the model that can simulate the choice of deploying or not deploying hydroelectric power may also improve the dispatch model.
    b. In order to address the availability of generation facilities for dispatching, the model allows plants to generate up to the product of their nameplate capacity and their equivalent availability factor. Using this method, all plants on the system are available at all times, although they cannot generate their full nameplate capacity. To make this more realistic, the model could be extended so that each day individual plants may or may not be available to dispatch their full nameplate capacity using a probabilistic simulation based on their equivalent availability factors.
    c. The model uses a static value of avoided capacity of 80 $/kW-yr. In reality, generation capacity costs are dependent on the interaction of supply and demand and thus dynamic in nature. Making avoided capacity costs dynamic in the model could improve the model.
    d. The modeling done in this project looked at the MISO system as a whole, and not at a more localized level; the modeling did not, for example, attempt to calculate locational marginal prices. The electricity grid is replete with localized characteristics that may affect the returns on demand response including transmission bottlenecks and localized supply and demand characteristics. Additionally, the model assumes that demand response is rolled out throughout all of MISO. In reality, there will likely be some utilities that will begin deployment of demand-response pricing while others will not.

2. **Model potential savings under a scenario in which demand growth continued at historical average since 2008.** As noted above, the economic downturn moved MISO away from the very steep parts of the supply curve, which significantly reduces the economic savings from demand response programs. Analysis with greater overall off-peak and peak demand would provide information about potential savings from demand response if electricity consumption rapidly recovers to pre-recession levels. This scenario could yield substantially different results
3. **DTE should use its pilots to test customer response to various dynamic pricing structures, various rates within those structures, various peak window lengths, and various configurations of enabling technology.** There is significant uncertainty around the level of demand response that DTE's customers will exhibit under dynamic pricing tariffs. Pilots give DTE the opportunity to test for many different variables and track in detail how its customers will respond and the corresponding economic benefit DTE will reap in a large scale deployment of AMIs and dynamic pricing tariffs. Below, we recommend the specific programs and variables for DTE's pilots.
    a. Pilot a CPP/PTR with enabling technology, TOU with enabling technology, and CPP/TOU with and without enabling technology. Our research and the estimated demand response for DTE's service territory conducted by the Brattle Group suggest that these three programs will provide the greatest demand response and economic benefit for DTE. However, it is unclear which program will provide the greatest benefit across various customer segments. Therefore, DTE should conduct pilots for all of these across customer segments to determine the best tariff structure for their demographic population.
    b. DTE should offer a peak period window of 4, 5 and 6 hours across pilots to test for movement and height of the peak. This test will create certainty around the window which will create the greatest economic benefit to DTE arising from avoided capacity. With a longer event window, enabling technology becomes more valuable and a better investment. This added technology will enable DTE to further increase its savings from rolling-out these new dynamic pricing tariffs.
    c. Pilots should incorporate the features of the most successful pilots already conducted across the US as described in Section 5, Attributes of Successful Demand Response Programs.
4. **DTE should test two and three hour CPP windows with higher differentials to test the viability of a staggered CPP tariff.** We believe this tariff represents an opportunity for DTE to distinguish itself as a cutting edge utility while benefiting economically from this novel price structure. We recommend testing the viability of such a tariff using ProMod and DTE-specific customer elasticities and, if estimates appear positive, rolling it out along with the other recommended tariffs.

Appendix A - DTE's Residential Rate Options

Standard Residential Rates

Residential Electric Service Rate Code: 060	
Power Supply Charges	
First 17kWh per day	6.486 c per kWh
Additional kWh	7.896 c per kWh
Delivery Charges	
Distribution kWh	3.547 c per kWh
Service Charge	$6.00 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Senior Citizen Residential Electric Service Rate Code: 053	
Available to customers who are age 62 or older, head of household and average less than 665 kWh a month.	
Power Supply Charges	
First 17kWh per day	4.575 c per kWh
Additional kWh	13.340 c per kWh
Delivery Charges	
Distribution kWh	.969 c per kWh
Service Charge	$6.00 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Interruptible Space Conditioning Service Rate Code: 086	
Customer's central air conditioning or central heat pump must be wired to a separate meter.	
Power Supply Charges (June – October)	
All kWh	5.657 c per kWh
(November – May)	
All kWh *Delivery Charges*	3.761 c per kWh
Distribution kWh (Year Round)	3.823 c per kWh
Service Charge (June-Oct)	$1.95 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Water Heating Service Rate	
Customer's water heater must be wired to a separate meter.	
Controlled Service(Interruptible) Rate Code: 007	
Power Supply Charges	
All kWh	3.740 c per kWh
Delivery Charges	
Distribution kWh (Year Round)	2.833 c per kWh
Service Charge (June-Oct)	$1.95 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Controlled Service(Non - Interruptible) Rate Code: 005	
Power Supply Charges	
All kWh	5.355 c per kWh
Delivery Charges	
Distribution kWh (Year Round)	2.833 c per kWh
Service Charge (June-Oct)	$1.95 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Special Rates for Space Heating

Whole House Rate Code: 040	
For electrically heated homes	
Power Supply Charges (June – October)	
First 17kWh per day	6.486 c per kWh
Additional kWh per day	7.896 c per kWh
(November – May)	
First 20 kWh per day	6.925 c per kWh
Additional kWh per day	5.451 c per kWh
Delivery Charges	
Distribution kWh (June - October)	3.539 c per kWh
Distribution kWh (November – May)	2.756 c per kWh
Service Charge (Jun)	$1.95 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Special Rates for Time of Day

Whole House Rate Code: 084	
Limited to 10,000 customers. On-peak hours Mon-Fri 11am – 7pm	
Power Supply Charges (June – October)	
All on-peak kWh	11.550 c per kWh
All off-peak kWh	3.650 c per kWh
(November – May)	
All on-peak kWh	9.770 c per kWh
All off-peak kWh	3.545 c per kWh
Delivery Charges	
Distribution kWh (June - October)	4.480 c per kWh
Service Charge (Jun)	$19.00 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Space Conditioning, Water Heating, or Electric Vehicle Rate Code: 032,034,036	
Limited to 5,000 customers. On-peak hours Mon-Fri 11am – 7pm. This rate is available to customers using geothermal heating and cooling	
Power Supply Charges (June – October)	
All on-peak kWh	9.925 c per kWh
All off-peak kWh	3.495 c per kWh
(November – May)	
All on-peak kWh	4.670 c per kWh
All off-peak kWh	3.460 c per kWh
Delivery Charges	
Distribution kWh (Year Round)	1.778 c per kWh
Service Charge (Jun)	6.70 c per day
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Optional Whole House (Farm) Rate Code: 020	
This rate is no longer offered to new customers. On-peak hours Mon-Fri 11am – 7pm	
Power Supply Charges	
All on-peak kWh	7.318 c per kWh
All off-peak kWh	4.015 c per kWh
Delivery Charges	
Distribution kWh (June - October)	4.107 c per kWh
Service Charge (Jun)	$6.51 per month
Power Supply Surcharges and Credits	.0009 c per kWh
Delivery Surcharges and Credits	.6824 c per kWh

Appendix B – Consumers Energy Rate Schedules

<u>Standard Residential Rates</u>

Residential Electric Service Rate: *RS*	
Power Supply Charges (June – September)	
First 600kWh per month	4.7517 c per kWh
Additional kWh	8.4687 c per kWh
(October – May)	
All kWh	4.7517 c per kWh
Delivery Charges	
Distribution kWh	2.6082 c per kWh
System Access Charge	$6.00 per month
Surcharges	4.5 c per kWh

<u>Time of Use Rates</u>

Residential Service Time of Day Secondary Rate: *RT* *On Peak Hours: 11:00 am – 7:00 pm*	
Power Supply Charges (June – September)	
On Peak	8.0012 c per kWh
Off Peak	4.5532 c per kWh
(October – May)	
On Peak	5.2654 c per kWh
Off Peak	4.2006 c per kWh
Delivery Charges	
Distribution kWh	2.6082 c per kWh
System Access Charge	$6.00 per month
Surcharges	4.5 c per kWh

Appendix C - Additional Rate Structures

Wisconsin Public Service

Regular Customer Rates	
$0.08487 per kWh	Current Urban Customer Rate
$0.08970 per kWh	Current Rural Customer Rate

Time of Use Savings Rate	
$0.04491 per kWh	Rate for Urban Customers during Time-of-Use electric savings hours
$0.04771 per kWh	Rate for Rural Customers during Time-of Use electric savings hours
$0.17961 per kWh	Time-of-Use rate for Urban Customers during peak usage hours
$0.19082 per kWh	Time-of-Use rate for Rural Customers during peak usage hours

Wisconsin Electric Power Company

Standard Rate		*Time of Use*	
		On Peak	Off Peak
Delivery Charge	3.890 cents/kWh	22.171 cents/kWh	4.243 cents/kWh
Power Supply Charge	6.716 cents/kWh	Included in Delivery Charge	
Total Cost per kWh	10.606 cents/kWh	22.171 cents/kWh	4.243 cents/kWh

Appendix D – Sample Marginal Cost Curve Calculation

Plant name: Warner Lambert
Location: Michigan
Fuel Type: Natural Gas
Nameplate Capacity: 12.4 MW
Capacity Factor: 24%
SOx output: .0306 lb/MWh
Heat Rate: 8500 BTU/kWh
Fuel Price: $6.42/MBTU
Equivalent Availability: 91%
Net Capacity: 11.33 MW

To calculate how this plant fits into the overall MISO marginal cost curve, we first multiplied the plant capacity by the plant equivalent availability factor to determine the "Net Capacity," which is 11.32 MW. This means that, on average, the Warner Lambert plant provides 11.32 MW of capacity to MISO (Note that for hydro and wind, we use an average capacity factor from 2004-2005 eGRID data, the most recent years available, instead of an equivalent availability factor. Capacity factors more accurately represent wind and hydro availability than do equivalent availability factors due to the intermittent, weather-determinant nature of these resources).

To calculate at what price this plant will bid into MISO, we need to calculate marginal cost for the plant. This is calculated first by taking the plant's heat rate (8.5 MBTU/MWh) and multiplying by the price of natural gas on a specific date. Next, we add the cost of SOx by multiplying the SOx price ($/lb) times the emissions rate (lb/MWh) for the plant. For Warner Lambert, the fuel cost is $6.42/MBTU x 8.5 MBTU/MWh, or $54.57/MWh. The SOx cost is .0306 lb/MWh * $0.10/lb, which, when added to the fuel costs, brings the total marginal cost for Warner Lambert to $54.57.

Of course, this plant is only called upon when demand requires its use. In terms of the overall MISO marginal cost curve, this plant would be called upon when demand reaches approximately 95,000 MW. Below that level of demand, there are less expensive plants (in terms of marginal cost) that are called into use. Most of these plants are coal, nuclear, wind, and landfill gas facilities that have very low marginal costs.

The overall MISO marginal cost curve is computed by doing similar calculations for all power plants within the MISO service territory.

Appendix E – Summary of Results of Various Scenarios

Table 13 - Summary Statistics of Tariffs Using Various Peak Window Lengths

Rate Plan	Savings/Cost Type	4-Hour Window	5-Hour Window	8-Hour Window
CPP/TOU/Tech				
	Avoided Energy	$ 194,600,000	$290,000,000	$636,000,000
	Avoided Capacity	$ 438,700,000	$846,000,000	$846,000,000
	Technology Cost	$ (925,000,000)	($925,000,000)	($925,000,000)
	Total	**($291,700,000)**	**$211,000,000**	**$557,000,000**
TOU/Tech				
	Avoided Energy	$ 174,200,000	$265,000,000	$602,000,000
	Avoided Capacity	$ 398,500,000	$611,000,000	$611,000,000
	Technology Cost	($925,000,000)	($925,000,000)	($925,000,000)
	Total	**$ (352,300,000)**	**($49,000,000)**	**$288,000,000**
PTR				
	Avoided Energy	$ 50,000,000	$50,000,000	$114,000,000
	Avoided Capacity	$ 300,000,000	$305,000,000	$305,000,000
	Technology Cost	0	$0	$0
	Total	**$ 350,000,000**	**$355,000,000**	**$419,000,000**
CPP/TOU				
	Avoided Energy	$ 39,000,000	$60,000,000	$122,000,000
	Avoided Capacity	$ 360,000,000	$399,000,000	$399,000,000
	Technology Cost	0	$0	$0
	Total	**$ 399,000,000**	**$459,000,000**	**$521,000,000**

Table 14 - Distribution of Savings for Various Tariffs and Peak Window Lengths

Rate Plan	Savings/Cost Type	4-Hour Window	5-Hour Window	8-Hour Window
CPP/TOU/Tech				
	Avoided Energy	31%	26%	43%
	Avoided Capacity	69%	74%	57%
	Total	**100%**	**100%**	**100%**
TOU/Tech				
	Avoided Energy	30%	30%	50%
	Avoided Capacity	70%	70%	50%
	Total	**100%**	**100%**	**100%**
PTR				
	Avoided Energy	14%	14%	27%
	Avoided Capacity	86%	86%	73%
	Total	**100%**	**100%**	**100%**
CPP/TOU				
	Avoided Energy	10%	13%	23%
	Avoided Capacity	90%	87%	77%
	Total	**100%**	**100%**	**100%**

Appendix F - PRISM Model Simulations

In the preceding analysis, we utilized peak period electricity consumption changes from several previous dynamic rate pilots. However, due to limitations of this method, we used an additional approach to estimate consumer response to demand response tariffs which incorporates customer elasticities and specific attributes tailored to DTE. *The Brattle* Group modeled DTE consumer response to various demand-response tariffs, the results of which are summarized in Appendix H – Financial Modeling Results of Selected Tariffs from PRISM Simulation. Due to the schedule of this project we modeled a limited number (3) of the tariff structures using the MISO dispatch model used throughout this study. A summary of this work is included below.

As noted above, there are limitations to the approach we used to estimate electricity consumption changes based on previous pilots. The most significant limitation is the absence of specific price points within each rate design. In the approach described in our paper, we looked at the results of several past pilots to determine our expected electricity load changes from different rate design categories (e.g. CPP / TOU, PTR, etc.). Within the population of past pilots, however, there are several specific price points within each category of rate designs. To illustrate this point, consider the following: the mean reduction from a CPP / TOU w/ Tech, based on past pilots, is 36% (see Table **1**). This mean is derived from the results of 8 past pilots, each of which typically has different prices. For example, Pilot One could have a critical peak price to off peak price ratio of 10:1 ($0.50 /kWh CPP to $0.05 / kWh Off Peak). Pilot Two could have a critical peak price to off peak price ratio of 20:1 ($0.75 /kWh CPP to $0.0375 / kWh Off Peak). By using the mean response (albeit with high, medium, and low scenarios), we group all specific price points together (within a specific rate design category) and use an average impact to model the expected electricity consumption changes included in our model.

Another approach, hereinafter referred to as "Approach 2," is to set specific price points within each rate design category and calculate the expected impact based on those specific price points. Using the same illustration described in the paragraph above and holding all else constant, Approach 2 would result in two different estimated load impacts because the ratio of CPP to Off Peak price is 10:1 in one and 20:1 in the other. We would expect a larger reduction in the 20:1 scenario.

This is significant in that Approach 2 allows us to estimate the load impacts from several different specific price points. The approach used throughout our paper provides us only with a range of expected impacts based on classes of rate design categories, but not specific price points. Additionally, the results are not specifically tailored to DTE using factors such as average load per customer, air conditioner saturation rates, and weather patterns. Approach 2 takes the extra step of incorporating this DTE-specific data.

Finally, the approach used in the paper is limited in understanding how much load is conserved versus shifted and, for the shifted portion, to what specific hours the load is shifted. Approach 2 addresses this by specifically looking at each rate window (off peak, shoulder, and peak / critical peak) and determining the relative increase or decrease in each window.

Note that Approach 2 does not use own price and substitution electricity consumption elasticities specific to DTE customers because, to do so, data would need to be collected from actual DTE pilots. Because Approach 2 requires elasticities as an input, elasticities from a proxy utility that had previously run similar pilots were used (see further explanation below)

To calculate the expected impacts using Approach 2, we enlisted the services of Ahmad Faruqui and Ryan Hledik of the Brattle Group in San Francisco. The Brattle Group's methodology is as follows:

"To simulate customer response to each of DTE's dynamic rate designs, *The Brattle Group* relied on the Price Impact Simulation Model (PRISM).[c] The PRISM software captures the actual responses of thousands of customers on dynamic rates during several recent pricing experiments across North America. The responses from these experiments were tailored specifically to DTE's system characteristics and dynamic rate designs to produce likely estimates of load shape impacts for the average DTE residential customer.

PRISM simulates two distinct impacts on customer usage patterns. The first is called the "substitution effect," which captures a customer's decision to shift usage from higher priced peak periods to lower priced off-peak periods. The second impact is called the "daily effect" and captures the overall change in usage (i.e. conservation or load building) that is induced by differences in the average daily price of the new rate relative to the existing rate. The magnitude of these impacts depends on the structure of the dynamic rate that is being tested, as well as a number of factors that influence the relative price responsiveness a utility's customers (such as weather, central air conditioning (CAC) saturation, or presence of enabling technologies). For example, higher peak-to-off-peak price differentials produce greater reductions in peak demand. Additionally, the presence of enabling technology, such as programmable communicating thermostats (PCTs) or in-home displays (IHDs) will enhance a customer's ability to respond to price signals, either through automation or increased access to usage-related information.

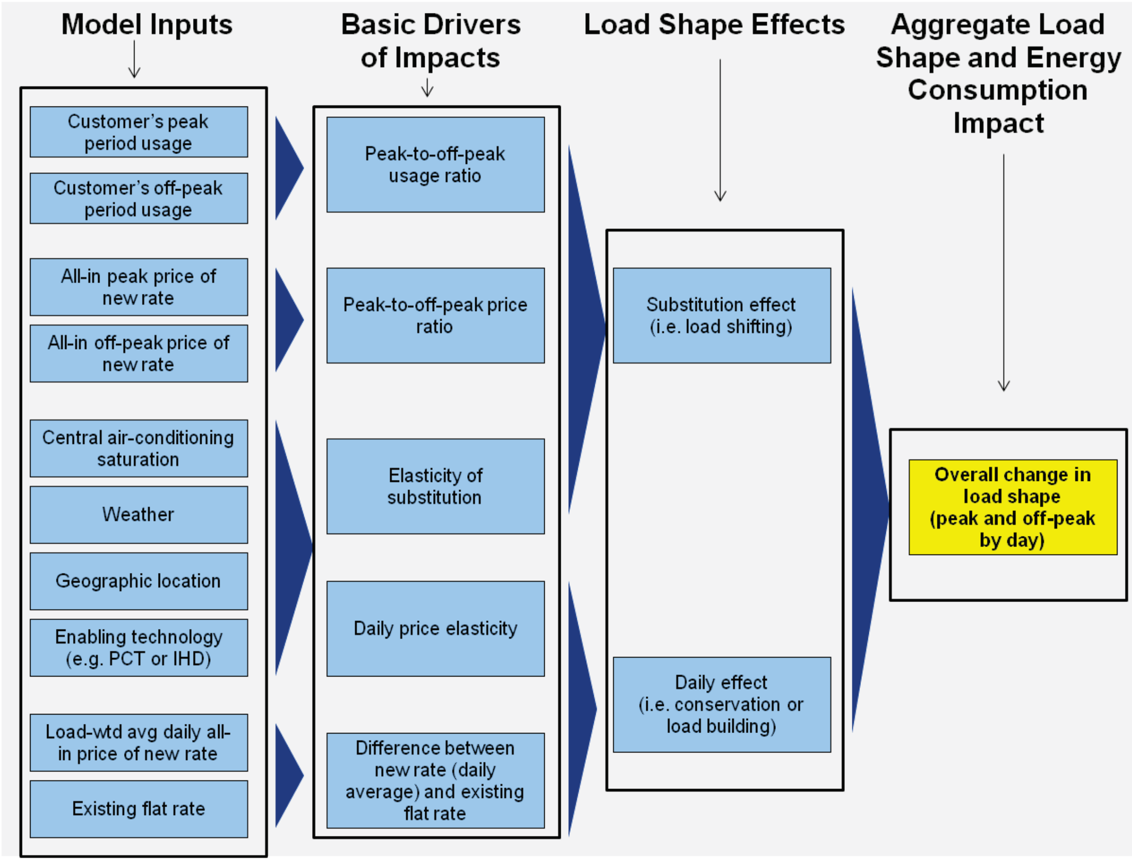
Of the elasticities estimated through recent dynamic pricing pilots, those produced in the Baltimore Gas & Electric (BG&E) experiment are likely the most representative of DTE's residential customers. This is due to identical CAC saturations of the two utilities (78%), similarly urban service territories, geographic locations east of the Rockies (indicating higher summer humidity than the Western U.S.), and similarities in the rate designs and technologies being evaluated. Due to these similarities, the residential elasticities from the BG&E experiment served as the basis for simulating DTE customer response.

Note that, for the purposes of this analysis, the IHD is assumed to be an energy orb. The energy orb changes colors depending on the price of electricity. For example, the orb could be green during off-peak hours, yellow during shoulder hours, red during peak hours, and flashing red during critical peak hours. This has the effect of making customers more aware of high priced hours and encourages load shifting.[d] The automating technology was assumed to be a PCT, which receives a signal directly from the utility and changes the thermostat to a pre-specified set point during critical events." See PRISM Flow Chart below:

[c] Recently, PRISM formed the basis for FERC's "A National Assessment of Demand Response Potential." For more information about the model, see Ahmad Faruqui, John Tsoukalis, and Ryan Hledik, "The Power of Dynamic Pricing," *The Electricity Journal*, April 2009.

[d] Note that other types of IHDs that provide more detailed information about usage patterns could affect customer usage differently, often by encouraging overall energy conservation.

PRISM Flow



<u>Rate Design Methodology</u>

In Approach 2, we designed many different rates (see summary in table below and actual rate designs in Appendix G –Tariffs and Expected Demand Reductions Using Prism Simulationto analyze their expected load impacts. Each rate was run through the PRISM by the Brattle Group. Below is a summary of the rates the Brattle Group analyzed.

Rate Design Category	Enabling Technology Included	Number of Different Rates Analyzed
CPP / TOU w/ Tech	Yes	12
CPP / TOU	No	7
CPP and Block Rate w/ Tech	Yes	1
CPP and Block Rate	No	1
TOU w/ Tech	Yes	10
TOU	No	5
PTR w/ Tech	Yes	7
PTR	No	7

In developing the rate designs, we considered the following:

1. Rate must be revenue neutral. We determined revenue neutrality using the following methodology: we obtained average hourly load data for residential customers within DTE's service territory. We multiplied total average monthly consumption per customer by DTE's current block prices (power supply cost only). This yielded the average residential monthly bill for power supply cost. We input the number of peak days that can be called by the utility (when applicable with a CPP rate), peak rate, shoulder rate and critical peak rate (where applicable). We then used a Solver optimization to solve for the off peak rate to set the total monthly bill per customer equal to the monthly bill per customer under the existing rate. If the resulting off peak rate was negative, or higher than the peak or shoulder rate, we simply adjusted one of the inputs until it made intuitive sense. It is the industry standard to assume no load change in applying new rates to determine revenue neutrality.
2. We sought to achieve rate designs that covered a reasonable spectrum of different rate categories, different prices within each category, inclusion and exclusion of a shoulder period / rate, number of event days that can be called (within CPP rate designs), and length of different pricing windows (off peak, shoulder, peak, critical peak).
3. We sought to analyze rates that we determined were easy to understand and would not excessively confuse customers. This was largely determined by best practices from the literature and our own sense of how we thought consumers may behave. It was not a rigorous scientific process.

Results of PRISM Model Simulation

Appendix G –Tariffs and Expected Demand Reductions Using Prism Simulationsummarizes the tariff structures modeled using the PRISM model as well as the expected demand reductions during critical peak, peak, shoulder, and off peak periods under these tariffs. The results of the PRISM simulations show demand reductions that are lower than the mean reductions presented in Table 1from the Brattle Group's study of previous demand response pilots. The difference between the mean demand reductions from previous demand response pilots and those shown in the PRISM model simulation is most profound for TOU tariffs. Given the lower expected demand reductions as modeled using the PRISM simulation, we expected lower financial return to demand-response pricing when using these expected demand shifts.

Appendix H – Financial Modeling Results of Selected Tariffs from PRISM Simulationshows the expected returns to selected tariffs from the PRISM model simulation. These results show financial outcomes ranging from a net loss of $496 million to a net gain of $551 million for deployment of the selected rate structures, which is lower than the results when using the mean reductions from prior pilots. These results lend further support to our conclusion that potential gains from demand response appear limited and that enabling technology may not be worth the cost of deployment. However, given the variance of the expected demand shifts from the PRISM simulation compared to the mean results of previous demand response pilots, DTE should empirically test the response of their customers to demand response before reaching firm conclusions.

It is important to note a limitation in the work performed by the Brattle Group. As previously mentioned, Brattle used elasticities from a Baltimore Gas and Electric pilot. The actual load reductions during the peak periods (non CPP events) for the BGE pilot were low (between 1% and 5% depending on the use of enabling technology).This occurred because there was not much of a price difference on the non-CPP days in the BGE pilot. The peak period rate was the same as the pre-dynamic pricing rate. The off-peak rate was of course lower but the price differential between peak and off-peak was considerably smaller than in some of the other pilots. The significance of this is that elasticities used in the PRISM were from one data point so any variation in actual elasticities by DTE customers, with respect to BGE elasticities, would alter the results. The further signifies the importance that DTE should employ several well designed pilots to determine actual elasticities of its customers.

Appendix G –Tariffs and Expected Demand Reductions Using Prism Simulation

Table 15 - Summary of Rate Plans Modeled Using PRISM Simulation

		Critical Peak Period (Hour Ending)		Peak Period (Hour Ending)		Shoulder Period (Hour Ending)		Rates				Consumption Change (%)					
												Critical Day			Non-Critical day		
#	Rate	Start	End	Start	End	Start	End	Off Peak Rate	Shoulder Rate	Peak Rate	Critical Peak Rate	Critical Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
1	CPP/TOU	14	18	14	18	7	23	$ 0.02	$ 0.05	$ 0.08	$ 0.50	-24%	4%	9%	-4%	1%	6%
2	CPP/TOU	14	18	14	18	9	22	$ 0.03	$ 0.05	$ 0.09	$ 1.00	-32%	4%	8%	-5%	1%	4%
3	CPP/TOU	13	18	13	18	9	22	$ 0.03	$ 0.05	$ 0.09	$ 0.75	-28%	5%	9%	-5%	1%	5%
4	CPP/TOU	13	18	13	18	9	22	$ 0.03	$ 0.05	$ 0.09	$ 0.75	-22%	3%	6%	-3%	1%	4%
5	CPP/TOU	13	18	13	18	9	22	$ 0.03	$ 0.05	$ 0.09	$ 0.75	-24%	4%	7%	-4%	1%	4%
6	CPP/TOU	14	18	14	18	-	-	$ 0.06	N/A	$ 0.08	$ 0.50	-22%	N/A	4%	-2%	N/A	1%
7	CPP/TOU	15	18	15	18	-	-	$ 0.04	N/A	$ 0.25	$ 0.50	-25%	N/A	5%	-17%	N/A	4%
8	CPP/TOU	14	18	14	18	-	-	$ 0.04	N/A	$ 0.08	$ 1.00	-32%	N/A	6%	-4%	N/A	2%
9	CPP/TOU	14	18	14	18	-	-	$ 0.04	N/A	$ 0.08	$ 1.00	-25%	N/A	4%	-3%	N/A	2%
10	CPP/TOU	14	18	14	18	-	-	$ 0.04	N/A	$ 0.08	$ 1.00	-27%	N/A	4%	-3%	N/A	2%
11	CPP/TOU	13	20	13	20	-	-	$ 0.06	N/A	$ 0.09	$ 0.20	-10%	N/A	5%	-3%	N/A	2%
12	CPP/TOU	14	18	14	18	7	23	$ 0.02	$ 0.05	$ 0.08	$ 0.50	-14%	1%	4%	-2%	1%	4%
13	CPP/TOU	14	18	14	18	9	22	$ 0.03	$ 0.05	$ 0.09	$ 1.00	-20%	1%	3%	-3%	1%	3%
14	CPP/TOU	13	18	13	18	9	22	$ 0.03	$ 0.05	$ 0.09	$ 0.75	-17%	1%	3%	-2%	1%	3%
15	CPP/TOU	14	18	14	18	-	-	$ 0.06	N/A	$ 0.08	$ 0.50	-13%	N/A	1%	-1%	N/A	1%
16	CPP/TOU	15	18	15	18	-	-	$ 0.04	N/A	$ 0.25	$ 0.50	-15%	N/A	2%	-10%	N/A	2%
17	CPP/TOU	14	18	14	18	-	-	$ 0.04	N/A	$ 0.08	$ 1.00	-20%	N/A	1%	-2%	N/A	1%
18	CPP/TOU	13	20	13	20	-	-	$ 0.06	N/A	$ 0.09	$ 0.20	-6%	N/A	2%	-1%	N/A	1%
21	TOU	-	-	14	18	7	23	$ 0.02	$ 0.05	$ 0.08	N/A	N/A	N/A	N/A	-4%	1%	6%
22	TOU	-	-	14	20	-	-	$ 0.05	N/A	$ 0.15	N/A	N/A	N/A	N/A	-9%	N/A	4%
23	TOU	-	-	14	18	7	22	$ 0.05	$ 0.08	$ 0.11	N/A	N/A	N/A	N/A	-4%	-1%	4%
24	TOU	-	-	14	18	7	22	$ 0.05	$ 0.08	$ 0.11	N/A	N/A	N/A	N/A	-3%	0%	3%
25	TOU	-	-	14	18	7	22	$ 0.05	$ 0.08	$ 0.11	N/A	N/A	N/A	N/A	-4%	0%	4%
26	TOU	-	-	15	18	-	-	$ 0.05	N/A	$ 0.20	N/A	N/A	N/A	N/A	-13%	N/A	3%
27	TOU	-	-	15	18	-	-	$ 0.05	N/A	$ 0.20	N/A	N/A	N/A	N/A	-10%	N/A	2%
28	TOU	-	-	15	18	-	-	$ 0.05	N/A	$ 0.20	N/A	N/A	N/A	N/A	-11%	N/A	2%
29	TOU	-	-	10	22	-	-	$ 0.06	N/A	$ 0.09	N/A	N/A	N/A	N/A	-2%	N/A	3%
30	TOU	-	-	14	18	7	23	$ 0.02	$ 0.05	$ 0.08	N/A	N/A	N/A	N/A	-2%	1%	4%
31	TOU	-	-	14	20	-	-	$ 0.05	N/A	$ 0.15	N/A	N/A	N/A	N/A	-5%	N/A	2%
32	TOU	-	-	14	18	7	22	$ 0.05	$ 0.08	$ 0.11	N/A	N/A	N/A	N/A	-2%	0%	2%
33	TOU	-	-	15	18	-	-	$ 0.05	N/A	$ 0.20	N/A	N/A	N/A	N/A	-7%	N/A	1%
34	TOU	-	-	10	22	-	-	$ 0.06	N/A	$ 0.09	N/A	N/A	N/A	N/A	-1%	N/A	1%
35	PTR	14	18	14	18	7	23	$ 0.04	$ 0.07	$ 0.10	$ (0.50)	-24%	3%	8%	-4%	0%	4%
36	PTR	14	18	14	20	-	-	$ 0.06	N/A	$ 0.12	$ (0.50)	-25%	N/A	5%	-6%	N/A	3%
37	PTR	14	18	14	18	-	-	$ 0.07	N/A	$ 0.09	$ (0.30)	-18%	N/A	4%	-2%	N/A	1%
38	PTR	14	18	14	18	7	22	$ 0.05	$ 0.08	$ 0.11	$ (1.00)	-31%	3%	8%	-4%	-1%	4%
39	PTR	15	18	15	18	-	-	$ 0.05	N/A	$ 0.20	$ (0.50)	-27%	N/A	4%	-13%	N/A	3%
40	PTR	11	17	10	22	-	-	$ 0.06	N/A	$ 0.09	$ (0.75)	-27%	N/A	7%	-2%	N/A	3%
42	PTR	14	18	14	18	7	23	$ 0.04	$ 0.07	$ 0.10	$ (0.50)	-15%	1%	3%	-2%	0%	2%
43	PTR	14	18	14	20	-	-	$ 0.06	N/A	$ 0.12	$ (0.50)	-15%	N/A	1%	-3%	N/A	1%
44	PTR	14	18	14	18	-	-	$ 0.07	N/A	$ 0.09	$ (0.30)	-11%	N/A	1%	-1%	N/A	0%
45	PTR	14	18	14	18	7	22	$ 0.05	$ 0.08	$ 0.11	$ (1.00)	-19%	0%	2%	-2%	0%	2%
46	PTR	15	18	15	18	-	-	$ 0.05	N/A	$ 0.20	$ (0.50)	-17%	N/A	1%	-7%	N/A	1%
47	PTR	11	17	10	22	-	-	$ 0.06	N/A	$ 0.09	$ (0.75)	-17%	N/A	2%	-1%	N/A	1%
49	CPP/TOU	15	18	15	18	10	22	$ 0.03	$ 0.06	$ 0.09	$ 1.00	-20%	0%	2%	-2%	0%	3%
50	CPP/TOU	15	18	15	18	-	-	$ 0.06	N/A	$ 0.09	$ 0.50	-13%	0%	1%	-2%	0%	1%
51	CPP/TOU	15	18	15	18	-	-	$ 0.05	N/A	$ 0.08	$ 1.00	-20%	0%	1%	-1%	0%	1%
52	TOU	-	-	15	20	-	-	$ 0.05	N/A	$ 0.15		N/A	N/A	N/A	-5%	N/A	2%
53	TOU	-	-	15	18	8	22	$ 0.05	$ 0.08	$ 0.11		N/A	N/A	N/A	-2%	0%	2%
54	PTR	15	18	15	20	-	-	$ 0.06	N/A	$ 0.12	$ (0.50)	-15%	N/A	1%	-3%	N/A	1%
55	PTR	15	18	15	18	-	-	$ 0.07	N/A	$ 0.09	$ (0.30)	-11%	N/A	1%	-1%	N/A	0%
56	PTR	15	18	15	18	8	22	$ 0.05	$ 0.08	$ 0.11	$ (1.00)	-20%	0%	2%	-2%	0%	2%
57	CPP/TOU	15	18	15	18	10	22	$ 0.03	$ 0.06	$ 0.09	$ 1.00	-32%	2%	7%	-5%	-1%	4%
58	CPP/TOU	15	18	15	18	-	-	$ 0.06	N/A	$ 0.09	$ 0.50	-23%	0%	3%	-3%	0%	1%
59	CPP/TOU	15	18	15	18	-	-	$ 0.05	N/A	$ 0.08	$ 1.00	-32%	0%	4%	-3%	0%	1%
60	TOU	-	-	15	20	-	-	$ 0.05	N/A	$ 0.15		N/A	N/A	N/A	-9%	N/A	3%
61	TOU	-	-	15	18	8	22	$ 0.05	$ 0.08	$ 0.11		N/A	N/A	N/A	-4%	-1%	3%
62	PTR	15	18	15	20	-	-	$ 0.06	N/A	$ 0.12	$ (0.50)	-25%	N/A	4%	-6%	N/A	2%
63	PTR	15	18	15	18	-	-	$ 0.07	N/A	$ 0.09	$ (0.30)	-19%	N/A	3%	-2%	N/A	1%
64	PTR	15	18	15	18	8	22	$ 0.05	$ 0.08	$ 0.11	$ (1.00)	-32%	2%	6%	-4%	-1%	3%

Appendix H – Financial Modeling Results of Selected Tariffs from PRISM Simulation

Table 16 - Summary of Financial Modeling of Various Tariffs From PRISM Simulation

Rate #	Description	Avoided Energy	Avoided Capacity	NPV Cost Savings	Technology Cost	Net NPV
#1	CPP/TOU w/ Technology	($1,000,000)	$375,000,000	$374,000,000	($925,000,000)	($551,000,000)
#2	CPP/TOU w/ Technology	$22,000,000	$407,000,000	$429,000,000	($925,000,000)	($496,000,000)
#8	CPP/TOU w/ Technology	$18,000,000	$372,000,000	$390,000,000	($925,000,000)	($535,000,000)
#21	TOU w/ Technology	($44,000,000)	$97,000,000	$53,000,000	($924,999,999)	($871,999,999)
#26	TOU w/ Technology	$24,000,000	($64,000,000)	($40,000,000)	($925,000,000)	($965,000,000)
#35	PTR w/ Technology	$45,000,000	$386,000,000	$431,000,000	($925,000,000)	($494,000,000)
#36	PTR w/Technology	$2,000,000	$361,000,000	$363,000,000	($925,000,000)	($562,000,000)
#49	CPP/TOU	$3,000,000	$7,000,000	$10,000,000	$0	$10,000,000
#61	TOU w/ Technology	$11,000,000	$13,000,000	$24,000,000	($925,000,000)	($901,000,000)
#64	PTR w/ Technology	$58,000,000	($46,000,000)	$12,000,000	($925,000,000)	($913,000,000)

Endnotes

[1] Faruqui, A. et al. May 16, 2007. *The Power of Five Percent.* The Brattle Group.
[2] Ibid.
[3] Energy Information Administration. 2009. Annual Energy Outlook 2009. Pg. 71.
[4] US Energy Information Administration. 2008. Electric Power Annual 2008. Pg. 35.
[5] Oak Ridge National Laboratory. March 2008. *ORNL Study Shows Hybrid Effect on Power Distribution*. http://www.ornl.gov/info/press_releases/get_press_release.cfm?ReleaseNumber=mr20080312-02.
[6] Van Doren, P. and Taylor, J. November 2004, *Rethinking Electricity Restructuring*. Policy Analysis No. 530, Cato Institute.
[7] Joskow, P. August 2005. *Markets for Power in the United States: an Interim Assessment*. Center for Energy and Environmental Policy Research, Sloan School of Management.
[8] Midwest ISO. “Midwest Market Concepts Study Guide Version 3.0.” Midwest ISO, <http://www.midwestiso.org/page/Market%20Info>.
[9] Conversation with Doug Ziemnick, Manager, Customer Research & Information, DTE Energy.
[10] Joskow, P. August 2005 *Markets for Power in the United States: an Interim Assessment*. Center for Energy and Environmental Policy Research, Sloan School of Management.
[11] Energy Information Administration, Independent Statistics and Analysis. April 2009. *Michigan State Energy Profile.*
[12] Ibid.
[13] Chambers, R. October 2003, *California Electricity Deregulation: Fool Me Once, Shame on You, Fool Me Twice…* Current Events Essay. http://www.stanford.edu/~robc1/work/deregulation.pdf.
[14] Michigan Public Service Commission. 2008. *Statistical Data of Total Sales of Electric Utilities in Michigan.* http://www.dleg.state.mi.us/mpsc/electric/download/electricdata.pdf.
[15] Ibid.
[16] Kavanaugh, K. April 17, 2008. *SE Michigan Wind Power.* Metromode Media, http://www.metromodemedia.com/features/MichiganWindPower0064.aspx.
[17] *Analysis of various CPP plans reviewed in this study.*
[18] Freeman, Sullivan & Co. 12/30/2008. *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company’s SmartRate Tariff*. Pg. 4.
[19] Ibid pg 9.
[20] Ibid pg 29.
[21] Herter, K. April 2007. *Residential implementation of critical-peak pricing of electricity*, Energy Policy, Volume 35, Issue 4. Pages 2121-2130.
[22] Ibid.
[23] Freeman, Sullivan & Co. 12/30/2008. *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company’s SmartRate Tariff*. Pg. 25.
[24] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group.
[25] Ibid.
[26] Ibid.
[27] 2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company’s SmartRate Tariff, Freeman, Sullivan & Co., 12/30/2008, PG 28
[28] Baltimore Gas & Electric, “Time-of-use,” http://www.bge.com/portal/site/bge/menuitem.20a019f5ee22079509c031e0da6176a0/
[29] Herter, K. April 2007. *Residential implementation of critical-peak pricing of electricity*, Energy Policy, Volume 35, Issue 4. Pages 2121-2130.
[30] Herter, K. April 2007. *Residential implementation of critical-peak pricing of electricity*, Energy Policy, Volume 35, Issue 4. Pages 2121-2130.
[31] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group.
[32] *Ibid.*

---

[33] *Ibid.*
[34] Herter, K. April 2007. *Residential implementation of critical-peak pricing of electricity*, Energy Policy, Volume 35, Issue 4. Pages 2121-2130.
[35] Faruqui, Ahmed; Ryan Hledik and Sanem Sergici. 2009. "Innovative Rate Development Made Easy." The Brattle Group, EEI Rates Course.
[36] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group: 28.
[37] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group: 39.
[38] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group: 19.
[39] Alcott, H. 2009. *Real Time Pricing and Electricity Markets*, Harvard University: 4.
[40] Alcott, H. 2009. *Real Time Pricing and Electricity Markets*, Harvard University: 6.
[41] Alcott, H. 2009. *Real Time Pricing and Electricity Markets*, Harvard University: 6.
[42] Alcott, H. 2009. *Real Time Pricing and Electricity Markets*, Harvard University: 12.
[43] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group.
[44] Ibid.
[45] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group: 13.
[46] National Renewable Energy Laboratory, "NREL Highlights Leading Utility Green Power Programs: Pricing programs give consumers clean power choices", Press Release, April 22, 2008.
[47] Ibid.
[48] Holland, Stephen P. and Mansur, Erin T. 2005. *The Distributional and Environmental Effects of Time-Varying Prices in Competitive Electricity Markets*. Social Science Research Network. http://ssrn.com/abstract=738585.
[49] Demand Response and Advanced Metering Coalition. 2004. "Overview of Advanced Metering Technology and Costs." http://www.dramcoalition.org/white_paper_overview_of_am_technologies_and_costs.htm.
[50] Demand Response and Advanced Metering Coalition, 2004. "Overview of Advanced Metering Technology and Costs." http://www.dramcoalition.org/white_paper_overview_of_am_technologies_and_costs.htm.
[51] Neenan, Bernard and Jiyong Eom. 2008. "Price Elasticity of Demand for Electricity: A Primer and Synthesis," Electric Power Research Institute, http://my.epri.com/portal/server.pt?space=CommunityPage&cached=true&parentname=ObjMgr&parentid=2&control=SetCommunity&CommunityID=404&RaiseDocID=000000000001016264&RaiseDocType=Abstract_id.
[52] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group: 2.
[53] Business Dictionary, "Enabling Technology," http://www.businessdictionary.com/definition/enabling-technology.html.
[54] Herter, K. April 2007. *Residential implementation of critical-peak pricing of electricity*, Energy Policy, Volume 35, Issue 4. Pages 2121-2130.
[55] George, S. and J. Bode. 2008. *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company's SmartRate Tariff.* Freeman, Sullivan & Co.: 4.
[56] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group: 30.
[57] Goldman, C. et al. 2004. Does Real-Time Pricing Deliver Demand Response?
A Case Study of Niagara Mohawk's Large Customer RTP Tariff. Lawrence Berkeley Livermore Laboratory: 16.
[58] Belson, K. "Rewarding Those Who Wait to Flip the Switch." New York Times
July 21, 2008.

[59] George, S. and J. Bode. 2008. *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company's SmartRate Tariff.* Freeman, Sullivan & Co.: 9.
[60] Faruqui, A. and S. Sergici. 2009. *Household Response to Dynamic Pricing of Electricity – A Survey of Experimental Evidence.* The Brattle Group: 30.
[61] George, S. and J. Bode. 2008. *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company's SmartRate Tariff.* Freeman, Sullivan & Co.: 13.
[62] George, S. and J. Bode. 2008. *2008 Ex Post Load Impact Evaluation for Pacific Gas and Electric Company's SmartRate Tariff.* Freeman, Sullivan & Co.: 32.
[63] Southern California Edison. 2007. "Automated Demand Response Fact Sheet," Southern California Edison, http://www.sce.com/NR/rdonlyres/08EBB404-C15D-4FD1-ABBD-E364A82C2A57/0/2008_0201_AutoDRFactSheet.pdf.
[64] San Diego Gas and Electric. 2008. "GNF Research Center Gets Energy Savings Down to a Science," San Diego Gas & Electric, *http://www.sdge.com/documents/business/savings/casestudies/NovartisCaseStudy.pdf.*
[65] Simon, Jeremy, "Credit card reward programs: a short history," November 14, 2006, creditcards.com http://www.creditcards.com/credit-card-news/reward-programs-a-short-history-1277.php.
[66] IBM Global Business Service and eMeter Strategic Consulting. 2007. "Ontario Energy Board Smart Price Pilot Report, Ontario Energy Board, http://www.oeb.gov.on.ca/documents/cases/EB-2004-0205/smartpricepilot/OSPP%20Final%20Report%20-%20Final070726.pdf.
[67] Environmental Protection Agency. 2009. "EGRID2007 Version 1.1," <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.
[68] North American Reliability Corporation. 2009. "2004-2008 Generating Unit Statistical Brochure - All Units Reporting," Generating Availability Data System (GADS): Reports, <http://www.nerc.com/page.php?cid=4|43|47>.
[69] Energy Information Agency. 2009. "Annual Energy Outlook 2010," <http://www.eia.doe.gov/oiaf/forecasting.html>.
[70] Environmental Protection Agency. 2009. "EGRID2007 Version 1.1," <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.
[71] LCG Consulting, "*Industry Data*," <http://www.energyonline.com/Data/GenericData.aspx?DataId=10&MISO___Actual_Load>.
[72] Midwest ISO, "*Midwest ISO Transmission Expansion Plan,*" http://www.midwestmarket.org/publish/Document/254927_1254c287a0c_-7e5d0a48324a?rev=1
[73] Detroit Edison, "Historical Load Data: SLP 1-Residential," http://www.suppliers.detroitedison.com/internet/infocenter/custdata/loadprofiles/profiles.jsp.
[74] Joskow, Paul L. 2005. *Markets for Power in the United States: An Interim Assessment*. MIT Center for Energy and Environmental Policy Research. http://web.mit.edu/ceepr/www/publications/workingpapers_2005_2008.html#2005.
[75] Midwest ISO. "*Midwest Market Concepts Study Guide Version 3.0.*" Midwest ISO, <http://www.midwestiso.org/page/Market%20Info>.
[76] Cappers, Peter, et al. 2009. *Financial Analysis of Incentive Mechanisms to Promote Energy Efficiency: Case Study of a Prototypical Southwest Utility*, Rep. Ernest Orlando Lawrence Berkeley National Laboratory.:18.
[77] Faruqi, Ahmad & Wood, Lisa. 2008. *Quantifying the Benefits Of Dynamic Pricing In the Mass Market*. The Brattle Group, Inc. and Edison Electric Institute.:20.
[78] Ibid.
[79] Midwest ISO, "*Midwest ISO Transmission Expansion Plan,*" < http://www.midwestmarket.org/publish/Document/254927_1254c287a0c_-7e5d0a48324a?rev=1>.
[80] United States Environmental Protection Agency. "*EGRID2007 Version 1.1*." <http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html>.
[81] United States Environmetal Protection Agency, Office of Atmospheric Programs, 2009. "*Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009*", www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf .:18.
[82] EPRI (Neenan), 2008. *Price Elasticity of Demand for Electricity* .:2.

[83] Ibid, Page iii
[84] Faruqui et al, 2009. *Household Response To Dynamic Pricing Of Electricity—A Survey Of The Experimental Evidence,* The Brattle Group.
[85] Faruqui et al. 2008. *Piloting The Smart Grid*. The Brattle Group.
[86] Faruqui et al. 2008. *Piloting The Smart Grid*. The Brattle Group.
[87] Midwest ISO, 2009 "*Midwest ISO Transmission Expansion Plan,*" <
http://www.midwestmarket.org/publish/Document/254927_1254c287a0c_-7e5d0a48324a?rev=1>.
[88] Federal Energy Regulatory Commission., "*Electric Power Markets: Midwest ISO,*"
http://www.ferc.gov/market-oversight/mkt-electric/midwest.asp.
[89] Midwest ISO, 2009, "*Midwest ISO Transmission Expansion Plan,*"
http://www.midwestmarket.org/publish/Document/254927_1254c287a0c_-7e5d0a48324a?rev=1.
[90]US Environmental Protection Agency, Office of Atmospheric Programs,2009. *Supplemental EPA Analysis of the American Clean Energy and Security Act of 2009,*
<www.epa.gov/climatechange/economics/pdfs/HR2454_SupplementalAnalysis.pdf>:18.