



Detroit Edison and Demand Response

An Assessment of National Trends and Implications for Detroit Edison and the State of Michigan

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**Prepared by Load Research Group, DTE Regulatory Affairs
Researched and Written by Jomo Thorne, ADDP Finance Consultant**

For more information contact:

Mark Williamson
Manager, Detroit Edison Load Research
(313) 235-8712
williamsonm@dteenergy.com

TABLE OF CONTENTS

EXECUTIVE SUMMARY.....	4
SECTION 1: WHY DEMAND RESPONSE.....	6
I. Definition and Overview.....	6
II. Drivers	8
1) Lack of Capacity & High Demand	8
2) Economics of Load-Shedding During Peak Demand	10
3) Demand Response, the Electricity Market, and Cost-Containment	10
4) Initiative of the US Energy Policy Act of 2005	12
5) Advances in Metering Technology.....	13
III. Demand Response in Michigan.....	14
IV. National Demand for Electricity, Detroit Edison, and Demand Response.....	15
V. Summary	16
SECTION 2: DR PROGRAM OPTIONS.....	17
I. Range of Demand Response Programs.....	17
II. Measuring Effectiveness of Demand Response Mechanisms	20
1) Determining Value and Cost-effectiveness	20
2) Demand Response and Market Potential	23
3) Measuring Avoided Demand (M&V).....	25
III. Summary	26
SECTION 3: ADVANCED METERING AND DEMAND RESPONSE.....	28
I. AMR Market.....	29
II. Growth in AMI Market and “Smart” Meters.....	30
III. AMI Data Collection.....	34
IV. Meter Data Management.....	37
V. Technologies Enabled By AMI.....	37
VI. Summary	41
SECTION 4: MICHIGAN NEEDS ANALYSIS.....	42
I. Michigan’s Demand Response Stakeholders.....	42

TABLE OF CONTENTS (Cont.)

II. Customer Energy-Use Patterns.....	42
III. Stakeholder Interests and Preferences.....	45
IV. Customer Responsiveness: Potential Barriers and Mitigations	51
V. Recent Performance of Demand Response	53
VI. Summary	57
SECTION 5: DEMAND RESPONSE PILOT PROGRAM RECOMMENDATIONS.....	58
I. Critical Peak Pricing (CPP) Pilot.....	58
II. Real Time Pricing (RTP).....	64
III. Interruptible/Curtailable Rates	66
IV. TOU Rates.....	66
V. Prepaid Energy	68
SECTION 6: STRATEGIC CONSIDERATIONS	70
SECTION 7: PILOT PROGRAM IMPLEMENTATION	72
I. Purpose of Demand Response Pilot Program	72
II. Pre-Pilot Focus Groups.....	72
III. Pilot Roll Out	72
SECTION 8: CONCLUSION	74
APPENDECIES	75
Appendix A – Measured Benefits and Costs of Demand Response Cost-effectiveness Tests	75
Appendix B - Methods of Estimating Demand Response Penetration Rates	78
Appendix C – Factors Influencing Customer Response to Demand Response Programs	79
Appendix D – Steps for Estimating Demand Response Market Potential.....	80
Appendix E – AMI Data Collection Technologies and Vendors.....	81
Appendix F - Key AMI Organizations and Vendors	83
Appendix G – AMI Project Costs	84
Appendix H - Data Sources for LBNL Market Potential Simulation	85

EXECUTIVE SUMMARY

“Demand response” refers to the strategies and incentives designed to modify (reduce or shift) customer electricity demand. Demand response programs are pursued by Independent System Operators (ISOs), electric utilities and other load serving entities (LSEs) to offset capacity shortages, improve electric grid reliability, manage electricity costs, and ensure that customers receive signals that encourage load reduction during times when the electric grid is near its capacity.

In recent years demand response has become increasingly important to stakeholders with an interest in the costliness and reliability of electricity. Demand response programs may have significant impacts on a utility’s financial performance, level of customer satisfaction, and other determinants of competitive advantage.

Customers benefit from well managed demand response programs through incentives and reduced energy use, with minimal adverse effects. Financial benefits to customers include cost savings on electric bills from reduced electricity consumption when prices are high, or from consumer shift to usage during lower-priced hours. Utilities may experience operational and capital cost savings from avoided generation costs as well as avoided or deferred transmission and distribution costs. In addition, because demand response measures can be deployed in a relatively rapid fashion, these may contribute to the resolution of problems in load pockets on a shorter time frame than building new generation, transmission, or distribution, which can take years to complete.

Detroit Edison is ideally positioned to be a leader in developing the policy and technological context within which demand response may flourish in the state of Michigan. Detroit Edison’s demand response programs, while well regarded nationwide, do not offer its customers the variety of demand response options offered by utilities of comparable size and service territory.

There are many demand response program options for Detroit Edison and other Michigan LSEs to consider. The major category of demand response programs includes Direct Load Control (programs that allow utilities to remotely shut-down or cycle electrical equipment), Passive Control (programs that give customers financial incentives to curtail electricity use), and Time-Based Rates (programs that promote customer demand response via direct price signals).

The ultimate measure of a demand response program’s effectiveness is its ability to shift and/or reduce peak load demand in a cost-effective manner. While methodologies for determining cost-effectiveness, customer responsiveness, and actual load reductions have been developed, there is no consistency in methods across utilities, states, and ISOs. This paper examines national trends and discusses the opportunities available to Detroit Edison and the state of Michigan for developing said methodologies.

The development of next generation “smart” meters is part of a surge in demand response enabling technologies. Advanced Metering Intelligence (AMI) systems provide analytical tools for cost allocation and energy management. They also enable two-way communication and other functionalities that facilitate the automation of demand response. Detroit Edison is committed to an ambitious AMI deployment which will position the company as a national leader in advanced metering. The AMI deployment will give Detroit Edison the infrastructure

needed to execute demand response programs that provide benefits to the company and customers, and which may serve as models to other utilities.

Understanding the energy use patterns and motivations of residential, commercial, and industrial customers, as well as the interests of regulators and other LSEs will be important to the development of demand response programs. Aligning stakeholder interests, gauging customer responsiveness, and evaluating current trends and the performance of existing programs are essential. These insights will assist Detroit Edison in matching program features and options to Michigan energy use patterns and other stakeholder interests/characteristics, and in developing a strategy to target customer segments that enhance both utility operations and customer reliability and satisfaction.

Considering some of the strategic implications of developing a demand response program is important. Among other things, an effective demand response program may strengthen Detroit Edison's position as a reliable competitor, and improve customer satisfaction by facilitating the automation of demand response. In addition demand response implementation may provide branding opportunities that increase customer association of Detroit Edison with responsible energy stewardship and innovation.

Nationwide there is tremendous momentum behind demand response. Detroit Edison's Load Research group is taking a lead role in developing a robust portfolio of demand response programs that may include time-based rates such as Critical Peak Pricing (CPP), Real-Time Pricing (RTP) and multi-tiered Time of Use (TOU) rates. In addition the Load Research group is considering proposing further enhancements to the company's successful direct load management programs. The installation of AMI and other enabling technologies will provide the infrastructure of complementary technology to facilitate program delivery. Detroit Edison's Load Research group has the talent and expertise that will allow the company to play a central role in creating demand response program for the benefit of all stakeholders.

SECTION 1: WHY DEMAND RESPONSE

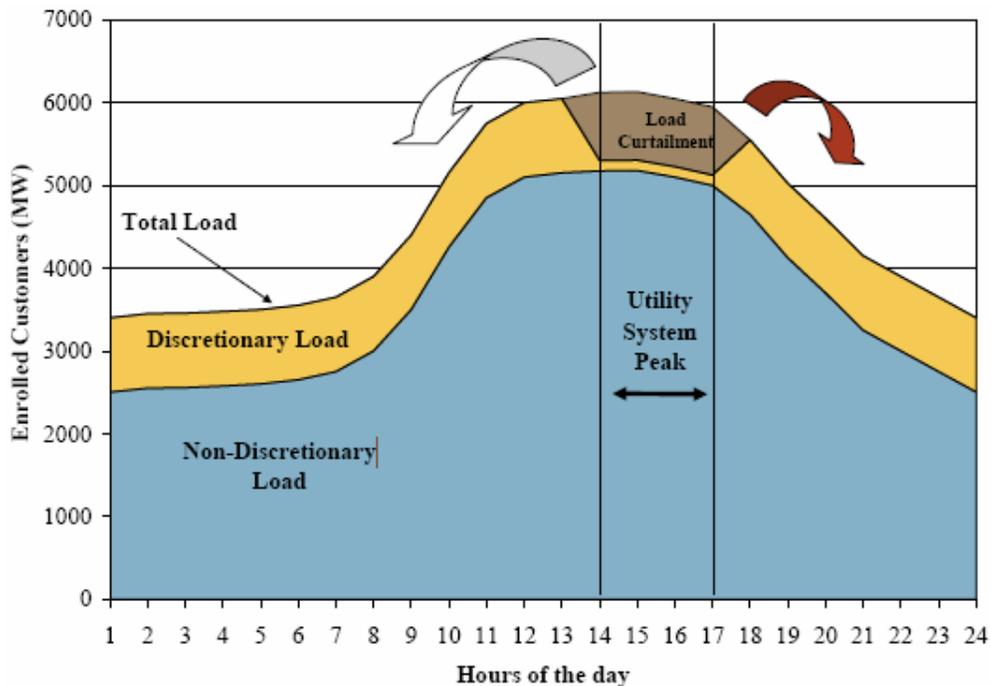
The following is a survey of national demand response initiatives and contains specific recommendations for the type of demand response measures Detroit Edison might undertake, and the process for rolling out a pilot program.

I. Definition and Overview

“Demand response” refers to the strategies and incentives designed to modify (reduce or shift) customer electricity demand. Demand response is pursued by Independent System Operators (ISOs), electric utilities and other load serving entities (LSEs) to offset capacity shortages, improve electric grid reliability, manage electricity costs, and ensure that customers receive signals that encourage load reduction during times when the electric grid is near its capacity. Among the reasons for the widespread creation of demand response programs are the prevention of future electricity crises and the reduction of electricity prices. Additional goals for price responsiveness include equity through cost of service pricing, and customer control of electricity usage and bills.¹

Graph 1-1 provides a schematic representation of potential peak load reductions achieved through a demand response program.

Graph 1-1 Potential Peak Reduction from a Demand Response Program



Source: Federal Energy Regulatory Commission

Market impacts of Demand Response

¹ Cogeneration Technologies. “Demand Response Programs.” Retrieved June 2007, from http://www.cogeneration.net/demand_response_programs.htm

Short-term market benefits of demand response include savings in variable supply costs brought about by more efficient use of the electricity system. Specifically, price responsiveness during periods of scarcity and high wholesale prices can temper high wholesale prices and price volatility. Decreases in price spikes and volatility should translate into lower wholesale and retail prices. Where customers are served by vertically integrated utilities, short-term benefits are limited to avoided variable supply costs. In areas with organized spot markets, demand response also reduces wholesale market prices for all energy traded in the applicable market. The amount of savings from lowered wholesale market prices depends on the amount of energy traded in spot markets. Demand response may also reduce a state's dependence on natural gas-fueled generation.²

Long-term market benefits of demand response come from the ability of demand response programs to (a) reduce system or local peak demand, thereby displacing the need to build additional generation, transmission, or distribution capacity infrastructure, and (b) adjust the pattern of customer electricity demand, which may result in a shift in the mix of peak versus baseload capacity.³

Benefits to LSEs and Customers

Beyond the broad improvements in market efficiency, participation in demand response programs creates specific financial, reliability, and operational benefits for market participants and LSEs.

Financial benefits to customers include cost savings on electric bills from reduced electricity consumption when prices are high, or from consumer shift to usage during lower-priced hours. Other consumer benefits include cost savings from any explicit financial payments received for agreeing to or actually curtailing usage as part of a demand response program. The significant increases in fuel and electricity costs experienced over the last several years provide additional motivation for customers to control and reduce their energy consumption.⁴

In addition to financial benefits, electricity customers gain from improved system reliability and the reduced likelihood of being involuntarily curtailed and incurring even higher costs.⁵

Operational and capital cost savings occur as system operators, LSEs, and distribution utilities benefit from avoided generation costs as well as avoided or deferred transmission and distribution costs. Since they can be deployed in a relatively rapid fashion, demand response programs can contribute to the resolution of problems in load pockets on a shorter time frame than building new generation, transmission, or distribution, which can take years to complete.⁶ Payback from demand response programs is more immediate than from building new generating capacity.

² Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 11). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

³ Ibid.

⁴ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 10). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

⁵ Ibid.

⁶ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 11). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

Lastly, by reducing electricity demand at critical times (e.g., when a generator or a transmission line unexpectedly fails), demand response dispatched by the system operator can help return electric system (or localized) reserves to pre-contingency levels.⁷

Other demand response benefits⁸ noted in research studies are more difficult to quantify, and their magnitude varies by region. The importance and perceived value of each of these benefits is subject to debate. These additional benefits include: (1) more robust retail markets, (2) additional tools to manage customer load, (3) opportunities for customers, retailers, and utilities to hedge risk exposure, (4) benefits to market performance, (5) the linking of wholesale and retail markets, and (6) potential benefits to the environment.

Types of Demand Response Programs

Demand response programs fall into three general categories: direct control, passive control, and time-based rates. These demand response mechanisms will be discussed in greater detail in the “Range of Demand Response Programs” section of this report.

Growing Interest in Demand Response

Demand response is increasingly important to state regulators and LSEs. Successful execution of demand response can have a significant impact on a utility’s competitive advantage by affecting its financial performance, its level of customer satisfaction, and the regulatory environment in which it operates.

II. Drivers

Demand response programs seek to abate the most serious consequences of real-time market price volatility and provide a stock of resources that help avoid electricity shortages. The convergence of market forces, policy innovation, and technology is driving the recent surge in interest in demand response among regulators, electric utilities, and other stakeholders. Specifically the key drivers of demand response are: (1) lack of generating capacity amidst rapidly increasing demand; (2) the economics of load-shedding during peak demand; (3) its importance to the operation of electricity markets; (4) initiatives of the US Energy Policy Act of 2005; and (5) advances in metering technology.

1) Lack of Capacity & High Demand

Demand for electricity in America continues to grow rapidly, while investment in new generation plants and transmission capacity has faltered.

⁷ Ibid.

⁸ For a more detailed discussion of these benefits please see pages 11-12 of FERC’s *Assessment of Demand Response & Advanced Metering* report.

Our nation's demand for electricity is at an all-time high. American homes use 21% more electricity today than they did in 1978. Consumer demand for electricity is projected to grow at an average rate of 1.5% per year through 2030 and overall electricity consumption is expected to increase by at least 40% by 2030.⁹

A 2006 report by the North America Electric Reliability Council (NERC) states that electric utilities are forecasting that demand will increase by 19% (141,000 MW) over the next ten years, while projected committed resources will only increase by 6% (67,000 MW).¹⁰ According to the Energy Information Administration (EIA), some 258 gigawatts (GW) of new capacity will be needed by 2030.¹¹ As illustrated by Graph 1-2, available capacity margins¹² in the U.S. are projected to decline over the 2006–2015 period.¹³ In addition, the expansion and strengthening of the transmission system continues to lag demand growth and expansion of generating resources in most areas.¹⁴ A 2001 study found that demand forecasts tend to underestimate demand during high growth periods such as the current one.¹⁵

⁹ U.S. Department of Energy, Energy Information Administration (February 2007). *Annual Energy Outlook 2007*. Washington, DC: Author

¹⁰ North America Electric Reliability Council (October 2006). *2006 Long-Term Reliability Assessment*. (pp. 6) Princeton, New Jersey: Author

ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2006.pdf

¹¹ U.S. Department of Energy, Energy Information Administration (February 2007). *Annual Energy Outlook 2007*. Washington, DC: Author

¹² “Capacity Margin” refers to the capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage. “Available Capacity Margin” refers to the difference between committed capacity resources and peak demand, expressed as a percentage of capacity resources.

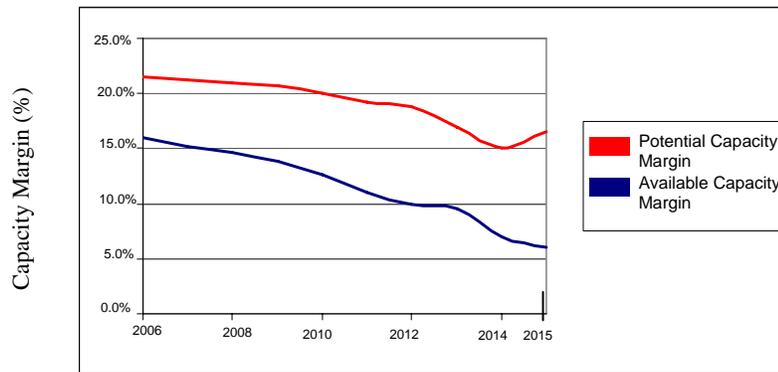
¹³ North America Electric Reliability Council (October 2006). *2006 Long-Term Reliability Assessment*. (pp. 11). Princeton, New Jersey: Author

ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2006.pdf

¹⁴ Ibid., pp. 7

¹⁵ At a February 2001 meeting of the NERC Load Forecasting Working Group, Yves Nadeau made a presentation on Quebec's Electricity Requirements Forecast Accuracy Evaluation. The report demonstrated that there was underestimation during high growth periods and overestimation during low growth periods. See page 3 of minutes at ftp://www.nerc.com/pub/sys/all_updl/pc/lfwg/lfwg0201m.pdf

Graph 1-2 Capacity Margins in United States Predicted to Decline Over Next Ten Years



Source: North America Electric Reliability Council

The growth in demand for electricity is apparent from the increase in consumption of energy-generation resources. For instance, year-to-date consumption¹⁶ of coal for power generation was up by 2.0%, petroleum liquids consumption was up by a staggering 62.2%, and consumption of natural gas was up by 20.1%. In the month of March 2007 residential and commercial sector sales increased 0.9 and 2.6 percent, respectively, when compared to March 2006. Total retail sales for that month were 293 billion kWh, an increase of 1.2% when compared to March 2006.¹⁷

Incentive-based demand response can be implemented significantly faster than building new generation or transmission. This flexibility allows resource constrained regions to respond rapidly to meet critical needs. As such, demand response resources are considered increasingly important options to offset the rising need for baseload generation.

2) Economics of Load-Shedding During Peak Demand

Since electrical systems are generally sized to correspond to the sum of all customers' maximum demand (plus margin for losses and reserves), lowering peak demand reduces overall plant and capital cost requirements.

Shedding loads during peak demand is important because it reduces both the need to operate peaker generating plants in the short-term, and investments in new power plants in the long-term. To respond to high peak demand, utilities build very capital-intensive power plants and lines. *Peak demand happens just a few times a year, so those assets run at a mere fraction of their capacity, yet they are necessary to maintain compliance with resource management regulations.* Demand response provides a way for utilities to defer large capital expenditures, and thus keep rates lower overall.¹⁸

3) Demand Response, the Electricity Market, and Cost-Containment

¹⁶ As of June 2007.

¹⁷ U.S. Department of Energy, Energy Information Administration (June 2007). *Electric Power Monthly*. Washington, DC: Author

http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html

¹⁸ "Demand Response – Short-term Inconvenience for Long-term Benefits," Wikipedia

http://en.wikipedia.org/wiki/Demand_response#Short-term_inconvenience_for_long-term_benefits

Residential and commercial electricity uses often vary drastically during the day. As a product electricity is not storable. There are different levels of generation efficiencies and different demand and supply conditions caused by weather and outages and so on.¹⁹ Sometimes there is plenty of capacity and the only incremental costs of producing electricity are fuel and some operating and maintenance (O&M) costs. At other times, the capacity constraint is binding, causing the incremental cost to increase greatly, and wholesale market prices to rise. As a result the wholesale price of electricity, reflecting the supply/demand interaction, varies constantly.²⁰

If the incremental costs (C) of expanding supply are more than the cost-recovery price (P) a utility is allowed to charge, a utility loses money (C-P) if it expands supply at the current price, and hence must increase prices in order to recover its full costs. But if the utility can buy demand reductions at prices less than the amount (C-P) it would lose expanding supply, it can meet growing demand with lower incremental losses and hence smaller increases in full cost-recovery prices.²¹ Therefore a utility with an obligation to supply electricity can improve consumers' incentives and reduce its own full-cost-recovery prices by paying for demand reductions, as long as such payments do not exceed the difference between marginal costs and retail prices they are "price corrections" rather than subsidies.

In most industries with highly volatile prices (such as fruits, vegetables, fresh fish, gasoline, or computer chips), retail prices adjust very quickly to reflect changes in the wholesale market for the good. While the cost of electricity power varies on very short time scales, most consumers face retail electricity rates that are fixed for months or years at a time, representing average production costs. This disconnect between short-term marginal electricity production costs and retail rates paid by consumers leads to an inefficient use of resources. Flat electricity prices encourage consumers to over-consume relative to an optimally efficient system during hours when electricity prices are higher than the average rates. As a result electricity costs may be higher than they would otherwise be because high-cost generators must sometimes run to meet the non-price responsive demand of consumers.²²

Employing pricing signals and other mechanisms, demand response programs attempt to bridge the divide between varying wholesale prices and the retail prices that consumers face. There are three underlying tenets to these programs: 1) unused electrical production facilities represent a less efficient use of capital (little revenue is earned when not operating); 2) electric systems and grids typically scale total potential production to meet projected peak demand (with sufficient spare capacity to deal with unanticipated events); and 3) by "smoothing" demand to reduce peaks, less

¹⁹ From testimony delivered before the California Energy Commission on 4-19-07. See pp. 151 at http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-19_workshop/2007-04-19_TRANSCRIPT.PDF

²⁰ Borenstein, S., Jaske, M., & Rosenfeld, A. (2002). *Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets*. Berkeley, California: University of California Energy Institute <http://www.ucei.berkeley.edu/PDF/csemwp105.pdf>

²¹ Roger Sant was the first economist to popularize this idea. But the arithmetic magic works only when $P < C$; when $P > C$, consumers already have too much incentive to conserve, a utility can lower its average cost and hence its full-cost recovery price by expanding supply, and a utility that pays anything to reduce demand must raise its average price to cover both the payment itself and its lost sales margin (P-C). (Source: "Economic Principles Of Demand Response in Electricity" http://www.eei.org/industry_issues/retail_services_and_delivery/wise_energy_use/demand_response/economicprinciples.pdf)

²² Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*.

investment in operational reserve²³ will be required, and existing facilities will operate more frequently. In addition, significant peaks may only occur rarely, such as two or three times per year, requiring significant capital investments to meet infrequent events.²⁴

It has been shown that a small change in system load can have a large impact on wholesale market prices for electricity. For instance it is estimated that a 5% lowering of demand would have resulted in a 50% price reduction during the peak hours of the California electricity crisis in 2000/2001.²⁵ Likewise a 2% reduction in peak demand (about 500 MW) would have reduced the clearing price from \$400 to \$175 per MWh (or about 56%) for the Independent System Operator of New England (ISO NE) on a peak day in the summer of 2001.²⁶

4) Initiative of the US Energy Policy Act of 2005

Regulatory directives and initiatives have historically catalyzed the growth of demand response. The rapid growth of demand-side management and load management in the 1980s and 1990s, for instance, was driven by state and federal encouragement and the implementation of integrated resource planning.²⁷ Recent policy innovations in states like California and New York have led to renewed growth in demand response as a resource. Support for demand response by Congress, the Department of Energy (DOE), the General Accounting Office (GAO), and the Federal Energy Regulatory Commission (FERC) have provided additional focus on the issue. Most recently, passage of the US Energy Policy Act of 2005 (EPAcT) has put demand response on the agenda for electric utilities and state regulators nationwide.

For instance EPAcT required the Secretary of Energy to submit "a report that identifies and quantifies the national benefits of demand response and makes a recommendation on achieving specific levels of such benefits by January 1, 2007" to the US Congress. Such a report was published in February 2006.²⁸

EPAcT highlighted the gap between potential and actual load shifting and reduction due to demand response. For instance the report estimates that the use of demand response is not widespread; approximately only 5% of customers are on some form of time-based rate or incentive-based program.²⁹ The report also found that in 2004 potential demand response capability equaled about

²³ Most of the revenue electric companies receive goes to pay operating and maintenance costs. Purchased power and fuel are the single largest operating expenses for an electric company. Thus any move to shave generation and purchased energy costs during critical times can have a significant effect on a utility's bottom line. (Source: Edison Electric Institute)

²⁴ "Demand Response – Importance for the Operation of Electricity Markets," Wikipedia
http://en.wikipedia.org/wiki/Demand_response#Importance_for_the_operation_of_electricity_markets

²⁵ Ibid.

²⁶ Peak Load Management Alliance. (2002). *Demand Response: Design Principles for Creating Customer and Market Value*. (pp. 5-6). See www.PeakLMA.com and http://www.naseo.org/committees/energyproduction/documents/demand_response_design_principles.pdf

²⁷ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 70). Washington, DC: Author
<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

²⁸ "Initiative of the US Energy Policy Act of 2005," Wikipedia
http://en.wikipedia.org/wiki/Demand_response#Initiative_of_the_US_Energy_Policy_Act_of_2005

²⁹ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. viii). Washington, DC: Author
<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

20,500 megawatts (MW), 3% of total U.S. peak demand, while actual delivered peak demand reduction was about 9,000 MW (1.3% of peak), leaving ample margin for improvement. It is further estimated that load management capability has fallen by 32% since 1996.³⁰

Factors affecting this trend include fewer utilities offering load management services, declining enrollment in existing programs, the changing role and responsibility of utilities, and changing supply/demand balance.³¹

The EPAct directed states and utilities to consider the costs and benefits of demand response programs and enabling technologies such as advanced meters.³² While states are not required to implement demand response or advanced metering, this congressional directive has indeed prompted action by state regulators, leading to the establishment of demand response pilot programs in a number of states.

5) Advances in Metering Technology

Customer response to price signals requires that end users and/or their devices know in advance what price will apply at what time, and for which service.³³ As such the penetration of advanced metering is important for the future development of electric demand responsiveness in the United States.³⁴

Improvements in integrated circuitry, control systems, and communication technologies have significantly increased the functionality of advanced meters and other demand response technologies. These advances make automated customer responses possible in more situations, allowing both greater customer receptivity and higher utility confidence that customers can and will respond to price-based demand response programs.³⁵

Dynamic pricing and the digital technology that enables communication of price information are symbiotic. Without enabling technologies dynamic pricing is meaningless; technology without economic signals to which to respond is extremely limited in its ability to coordinate the buying and selling of electricity in a way that optimizes network quality and resource use. The combination of dynamic pricing and enabling technologies changes the value proposition of demand response to the end user. Therefore a key requirement for most demand response programs is the availability of enabling technology.³⁶

The state of “smart metering” and other demand response enabling technologies will be discussed in greater detail in the “Advanced Meters and Demand Response” section of this report.

³⁰ “Initiative of the US Energy Policy Act of 2005,” Wikipedia

http://en.wikipedia.org/wiki/Demand_response#Initiative_of_the_US_Energy_Policy_Act_of_2005

³¹ Ibid.

³² Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 69-70). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

³³ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*.

³⁴ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. viii). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

³⁵ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*.

³⁶ Ibid.

III. Demand Response in Michigan

Detroit Edison is in the position to lead the policy and technological development of demand response solutions in the state of Michigan.

In its “21st Century Electric Energy Plan” the Michigan Public Services Commission (MPSC) projects that Michigan’s peak electric demand will grow at approximately 1.2% per year over the next 20 years. At this rate, and given the long lead-time necessary for major plant additions, additional baseload generation is projected to be necessary as soon as practicable (but no later than 2015).³⁷

The MPSC is currently exploring options to offset this rising need for baseload generation. Among others measures, the MPSC is incentivizing³⁸ utilities to develop a portfolio of mitigation strategies that includes energy efficiency/demand response, renewable energy, and traditional baseload generation.³⁹ In addition the MPSC issued an order⁴⁰ on June 12, 2007 initiating a collaborative process among the state’s LSEs to investigate the feasibility and potential benefit of widespread demand response measures that utilize advanced metering technology. These pilot programs will assess quantitative impacts, technical feasibility, and operational aspects of demand response measures, providing both data and practical experience. Should these pilot programs demonstrate the cost effectiveness of demand response programs the MPSC may seek the authority to require utilities to offer demand response programs to their customers.⁴¹

Detroit Edison is proactively working to craft a demand response strategy that will be beneficial to the company and its customers. Detroit Edison’s Load Research group is taking the lead in developing a proposal for a set of new tariffs for demand response that may include both time-based rates and further enhancements to the company’s direct load management program, to be implemented in conjunction with the installation of automated metering infrastructure (AMI) technology. This new demand response initiative will target customers in all three major segments (residential, commercial, and industrial).

³⁷ Michigan Public Service Commission. (2007). *MICHIGAN’S 21ST CENTURY ELECTRIC ENERGY PLAN*. (pp. 2) Lansing, MI: Author,

<http://www.cis.state.mi.us/mpsc/electric/capacity/energyplan/index.htm>

³⁸ For example, the MPSC’s plan calls for the creation of a new regulatory framework under which investor-owned utilities can build new generating facilities. Under this framework the MPSC would grant utilities a Certificate of Need (CON) as the end result of an Integrated Resource Plan (IRP) submission that evaluates the ability of renewable resources, energy efficiency/demand response measures, external markets, and existing traditional generation to meet forecasted demand. The conferral of a CON precludes any later challenge to the usefulness of a generation plant, thus enhancing the utilities’ ability to obtain financing for such a project (by reducing the risk that future revenues will not be available to cover the reasonable project costs).

³⁹ Michigan Public Service Commission. (2007). *MICHIGAN’S 21ST CENTURY ELECTRIC ENERGY PLAN*. (pp. 3). Lansing, MI: Author

<http://www.cis.state.mi.us/mpsc/electric/capacity/energyplan/index.htm>

⁴⁰ See MPSC press release “MPSC Starts Collaborative Proceeding for Demand Response Pilot Program” at

<http://www.michigan.gov/mpsc/0,1607,7-159-16377-170116--,00.html>, and text of the actual order at

http://www.cis.state.mi.us/mpsc/orders/electric/2007/u-15277_06-12-2007.pdf

⁴¹ Michigan Public Service Commission. (2007). *MICHIGAN’S 21ST CENTURY ELECTRIC ENERGY PLAN*. (pp. 7) Lansing, MI: Author

<http://www.cis.state.mi.us/mpsc/electric/capacity/energyplan/index.htm>

Michigan and Emerging MISO Electricity Market

Michigan relies on out of state power purchases. As such the availability of generation in the Midwest is important. The Midwest Independent System Operator (MISO) manages regional wholesale power markets, reliability, and planning.⁴²

MISO is in the process of establishing the Midwest Distributed Resource Initiative (MWDRI) to assess demand response in the region, explore additional demand response programs, and make recommendations for possible implementations.⁴³ MISO is also developing new market mechanisms for price responsiveness demand in order to help its member utilities fully participate in the Real-Time market as dispatchable resources, eligible to set market clearing prices.⁴⁴

IV. National Demand for Electricity, Detroit Edison, and Demand Response

Detroit Edison is committed to providing reliable and affordable electricity to its customers. Nationwide demand for electricity is at an all time high. For example, in 2006, the nation's electric output was the second highest yearly total ever recorded, falling just shy of the record set in 2005. The electric power industry set an all-time weekly electric output record in late July 2006, which was eclipsed only two weeks later.⁴⁵

Looking ahead, it is likely that more records for electricity use will be set. The population of the United States is anticipated to grow 23% between now and the year 2030, while the nation's gross domestic product is projected to double in that time. Electricity use will increase by at least 40% over the same time period.⁴⁶

This sustained growth in electricity demand requires electric companies to invest in new power plants, as well as the transmission and distribution infrastructure used to deliver the power where it is needed. The electric power industry has already begun increasing its capital expenditures to keep pace with growing demand. In 2005, capital expenditures totaled \$46.5 billion, while 2006 capital expenditures are expected to increase to nearly \$60 billion.⁴⁷

Detroit Edison currently has a total demand response capability of 540 MW, which approximately represent 5% of historic peak demand (~11,000 MW). The company's direct control program is the ***Interruptible AC program (IAC)*** through which customers' air conditioning units are remotely shut-down or cycled during peak periods. Some 280,000 residential customers participate in this program, and it is capable of 240 MW load reduction at peak. The company's IAC program is recognized nationwide for both the large number of participants and the amount of demand response resource it represents. The company will seek to add additional customers to this program, adding increasing interruptible capacity, within 5 years.

Through its passive control program the company offers payments, in the form of discount retail rates or separate incentive payments, to customers who reduce their electricity usage during peak

⁴² Edison Electric Institute. (July 2007). *Demand Response Review*. Washington, DC: Author, pp. 4

⁴³ Ibid.

⁴⁴ Edison Electric Institute. (July 2007). *Demand Response Review*. Washington, DC: Author, pp. 4

⁴⁵ Edison Electric Institute *The Financial Side Of The Electric Power Industry*, pp. 47

⁴⁶ Ibid.

⁴⁷ Edison Electric Institute *The Financial Side Of The Electric Power Industry*, pp. 47

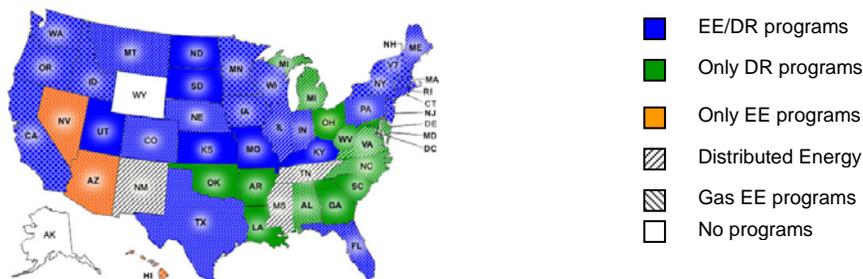
periods. Currently some 416 commercial and industrial (C&I) customers take advantage of the ***Interruptible/Curtailable Rates (D3.3, D8, R10)*** through which the company can secure 300 MW of load reduction at peak.

Detroit Edison’s main objective for demand response is to develop a robust program for all customer classes which has the potential to deliver significant load capacity. Some 140 MW of new DR capacity were filed with the U-15244 rate case in 2007. The company hopes to officially kick-off its demand response programs upon approval of the pending rate case U-15244. At that time the company will augment its demand response portfolio in support of the submitted Integrated Resource Plan (IRP).

The state of Michigan is ranked #10 in total net summer capacity (30,422 MW in 2005), and #12 in net generation (121,619,771 MWh in 2005), and Detroit Edison is among the top 20 electricity providers in the nation.⁴⁸ Even then, the state and the company are substantially behind their respective peers (top energy generating states and companies) in the number and type of demand response options offered. Graph 3 describes the national distribution of demand response and energy efficiency.

While Detroit Edison’s present portfolio of demand response programs is recognized nationwide for its effectiveness, the full potential for demand response remains largely untapped.

Graph 1-3 National Distribution of Demand Response and Energy Efficiency Programs



Source: DOE “Energy-Efficiency Funds and Demand Response Programs”
http://www1.eere.energy.gov/femp/program/utility/utilityman_energymanage.html

V. Summary

Demand response is increasingly important to utilities and may have important impacts on their financial performance, customer satisfaction, regulation, and has other implications for competitive advantage. Detroit Edison is moving in the direction of establishing robust demand response programs and is in a position to play a leading role in driving the policy innovations and technological advancements.

⁴⁸ U.S. Department of Energy, Energy Information Administration (June 2007). *State Electricity Profiles*, Table A1. Washington, DC: Author
http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html

SECTION 2: DR PROGRAM OPTIONS

I. Range of Demand Response Programs

Demand response programs fall into three general categories: direct control, passive control, and time-based rates.

Direct control refers to demand response programs that allow LSEs to remotely shut-down or cycle customers' electrical equipment, on short notice, to address reliability contingencies. Customers on a direct control program typically receive an incentive payment or bill credit in return for curtailment. Interrupting the use of service to customers' appliances on a random, individual basis, can reduce the overall system demand by creating artificial diversity in time of use.⁴⁹

The most common type of direct control program cycles the operations of air-conditioners or water heaters. In these programs, a one-way remote switch (also known as a digital control receiver) is connected to the condensing unit of an air conditioner or to the immersion element in a water heater. By remotely switching off the load at the appliance, peak loads can be reduced. Actual load reductions vary by customer usage patterns, size of the appliance, and climate. Direct control programs typically limit the number of times or hours that the customer's appliance can be turned off per year or season. In recent years, remote switches have become more sophisticated through the adoption of new technologies. Most new switches are individually addressable, allowing for more targeted reductions and the addressing of localized problems. In addition, system software upgrades can now be done wirelessly, and communication with switches can be conducted using public paging networks (instead of proprietary communications networks that are costly to build and maintain). Most switches also contain multiple relays so that air conditioners and water heaters can be controlled by the same switch with independent control strategies for each relay.⁵⁰

Detroit Edison's IAC program, PG&E's Base Interruptible (E-BIP), and Alabama Power's Standby Generator programs are good examples of direct control programs.

Passive control refers to demand response programs that give customers financial incentives to curtail electricity use during peak periods. Included in this category of programs are:

- **Interruptible/curtailable rates** – LSEs offer payments, in the form of discount retail rates or separate incentive payments, for customers to reduce their electricity usage during peak periods. These rates are constant nearly all of the time. When the system operator declares certain potential shortages, however, these customers are called upon to curtail electricity consumption. Curtailment is mandatory, and customers may be penalized if they fail to curtail.⁵¹ Despite the name, service to these customers is generally not actually physically interrupted. Rather, the price that they face increases dramatically. For instance, in one program in California, customers on interruptible rates were required during declared

⁴⁹ Walters, F. (1984). *The Art of Rate Design*. (pp. 85-86). Washington, DC: Edison Electric Institute

⁵⁰ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 46). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

⁵¹ Ibid., pp. 47

shortages either to stop consuming or to pay \$9.00 per kWh for their continued consumption, a more than 30-fold increase.⁵²

- Demand bidding/buyback programs – Programs that encourage large customers to offer to provide load reductions at a price at which they are willing to be curtailed.⁵³ While economic gain may incentive participants, from the perspective of a LSE demand bidding is not ideal, as it does not offer a reliable and controllable demand response resource.
- Demand-reduction programs (DRPs) – Programs that pay customers to reduce their consumption at critical times. Customers signed up for a DRP are eligible to be contacted by the utility or system operator with an offer of payment in return for the customer reducing consumption. These programs must first determine a baseline from which demand reduction can be measured. Once the baseline is set, the price offered for demand reduction determines the level of economic incentive to reduce demand when the system operator calls.⁵⁴
- Emergency demand response programs – Programs that provide incentive payments to customers for reducing their loads during reliability-triggered events. Curtailment, however, is voluntary.⁵⁵
- Capacity market programs – Programs through which customers commit to providing pre-specified load reductions when system contingencies arise, and are subject to penalties if they do not curtail when directed. These programs can be viewed as a form of insurance - in exchange for being obligated to curtail load when directed, participants receive guaranteed payments (i.e., insurance premiums).⁵⁶
- Ancillary-services market programs - Programs that allow customers to bid load curtailments in ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are called by the ISO/RTO, and may be paid the spot market energy price.⁵⁷

Time-based rates promote customer demand response via direct price signals. Included in this category of programs are:

- Time-of-use (TOU) – Tariff structure that allows retail prices to vary in a preset way within certain blocks of time (e.g. within a day and/or between seasons), reflecting the average

⁵² Borenstein, S., Jaske, M., & Rosenfeld, A. (2002). *Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets*. Berkeley, California: University of California Energy Institute

<http://www.ucei.berkeley.edu/PDF/csemwp105.pdf>

⁵³ Borenstein, S., Jaske, M., & Rosenfeld, A. (2002). *Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets*. (pp. 49-50). Berkeley, California: University of California Energy Institute

<http://www.ucei.berkeley.edu/PDF/csemwp105.pdf>

⁵⁴ Ibid.

⁵⁵ Borenstein, S., Jaske, M., & Rosenfeld, A. (2002). *Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets*. (pp. 48). Berkeley, California: University of California Energy Institute

<http://www.ucei.berkeley.edu/PDF/csemwp105.pdf>

⁵⁶ Ibid., pg. 49

⁵⁷ Borenstein, S., Jaske, M., & Rosenfeld, A. (2002). *Dynamic Pricing, Advanced Metering, and Demand Response in Electricity Markets*. (pp. 51). Berkeley, California: University of California Energy Institute

<http://www.ucei.berkeley.edu/PDF/csemwp105.pdf>

varying unit cost of production. TOU rates are adjusted infrequently and as such do not capture the price variation within a price block. For this reason TOU rates are often combined with a separate charge for peak usage. These “demand charges” are a price per kilowatt for the customer’s highest usage during the billing period (usually a month). Demand charges are based on the customer’s maximum usage (during a 15, 30, or 60 minute interval) regardless of whether that usage occurs at a time when the system as a whole has a tight supply/demand balance or not. Most of the meters that register maximum usage for demand charge billing are not capable of storing information indicating the precise date and time at which that maximum usage occurred.

- Critical-peak pricing (CPP) – Load use rates, superimposed on top of either TOU or flat pricing, that reflect real-time prices during a small number of critical hours of extreme system peaking. CPP programs typically limit the utility to call no more than 50 or 100 critical peak hours per year. CPP rates are triggered by system contingencies or high prices on wholesale market and are set much higher (sometimes 5 to 10 times higher) than flat/TOU rates. Variations in CPP include CCP-Variable, CCP-Fixed, CP-Rebates, and Critical Day Pricing (CDP).
- Real-time pricing (RTP) –In an RTP program the price of electricity varies on an hourly basis, reflecting instantaneous market conditions. Because rates on these plans come the closest to the cost of power as it fluctuates this program provides the most accurate price signals.⁵⁸ Rates are known only on a day-ahead or hour-ahead basis and communicated to customers via the internet and/or phone and text messaging. Participating in an RTP program does not mean that customers must buy all of their power at the real-time price. Hedging, purchasing power through a long-term contract before a period of system stress is evident, allows customers to stabilize their overall bill while still facing the real-time price for incremental consumption.

Program Administration

While any report of this kind must address the delicate subject of the funding and administration of demand response programs, demand response programs are typically funded by utilities with expectations of quick paybacks in avoided peaker costs. But questions persist. Who should own demand response programs – the state, utilities, or public utilities commissions? Should programs be centrally administered, by say, a state-sponsored third party administrator, or should they be administered by LSEs? Should administration costs be solely paid for by utility shareholders, or should all customers share in the cost? Table 2-1 describes demand response program administration options.

⁵⁸ From testimony delivered before the California Energy Commission on 4-19-07. See page 152 and http://www.energy.ca.gov/2007_energy_policy/documents/2007-04-19_workshop/2007-04-19_TRANSCRIPT.PDF

Table 2-1 Demand Response program administration options

	Description	Pros	Cons
Utility	<ul style="list-style-type: none"> • Utility collects funds for DR program through systems benefits charge • Utility designs, launches, and administers programs with or without oversight from state regulators 	<ul style="list-style-type: none"> • Utilities have experience and expertise in DR • Utilities well positioned to administer DR programs 	<ul style="list-style-type: none"> • Utilities have incentives to sell more power, not less • DR program success depends on customer-utility relationship
State or Third Party	<ul style="list-style-type: none"> • Utility collects funds for DR program through systems benefits charge and passes funds to the state or designated third party • The third party designs, launches, and administers programs typically with oversight from state regulators 	<ul style="list-style-type: none"> • Third parties do not have divided incentives • Third parties may administer DR program over geographic spread larger than any single utility service territory 	<ul style="list-style-type: none"> • Start up and administration costs associated with starting new administrative entity • Costs associated with building brand-awareness and customer relationships of new administrative entity

Source: Department of Energy

II. Measuring Effectiveness of Demand Response Mechanisms

The ultimate measure of a demand response program’s effectiveness is its ability to shift and/or reduce load demand during peak periods in a cost-effective manner. Specifically, three major areas should be considered when assessing the efficacy of a demand response program: (1) its cost effectiveness, (2) level of customer responsiveness to the program, (3) the ability to measure actual load reductions (M&V) and actual load-shed value.

1) Determining Value and Cost-effectiveness

The first concern in measuring the effectiveness of a demand response program is the extent to which it can lower the cost (to LSEs) of serving loads, and the impact that program implementation will have on ratepayers.

To measure the cost-effectiveness of demand response a number of value streams⁵⁹ must be considered, including:

- avoided supply costs of energy and demand⁶⁰

⁵⁹ All valued at marginal costs for the periods when there is a load reduction.

- delayed generation capacity additions
- deferred generation costs
- deferred transmission and distribution upgrade costs
- evaded high peak prices
- evaded hedging costs (options and futures)
- reduced line losses
- facilitated maintenance of the grid and generation resources
- incurred program administration costs⁶¹
- equipment and installation costs
- operations and maintenance costs
- marketing expenses

In general cost-effectiveness of demand response should be measured against the cost of supplying equivalent resources with generators, expanded transmission, or other traditional tools of control area operators.⁶²

The lack of a systematic methodology for assigning value to demand response and determining cost-effectiveness under different power system and economic conditions (especially when this value critically depends on the method of deployment) is a key challenge to the implementation of demand response. In 2004 the Demand Response Resource Center (DRRC) - a joint effort between the California Energy Commission and the Lawrence Berkeley National Laboratory – initiated a comprehensive evaluation aiming to “provide a clear path for developing a comprehensive methodology and framework for the evaluation of different DR technologies and program designs.”⁶³ Among other conclusions, the DRRC found that “the current standard practice used to value energy efficiency in California contains many useful elements for DR evaluation, but does not completely capture the entire value of DR.”⁶⁴

Attempts to (1) set protocols for estimating the load impacts of demand response programs, and (2) establish methodologies to determine the cost-effectiveness of demand response programs, are being pursued by a number of ISO/RTOs and state regulators nationwide.⁶⁵ For instance the California Public Utilities Commission (CPUC) initiated a rulemaking process in January 2007 with these two goals in mind.⁶⁶ A final ruling in this case is not expected until February 2008.

⁶⁰ Calculated using net program savings (savings net of changes in energy use that would have happened in the absence of the program).

⁶¹ Including initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value).

⁶² Foley, T. (2007). *How to Measure Cost-Effectiveness of Demand Response*. (pp. 1). Northwest Power and Conservation Council. Retrieved June 2007 from http://www.nwcouncil.org/energy/dr/meetings/2007_05/CEFINAL.pdf

⁶³ See California Public Utilities Proceeding R0404025 at <http://www.cpuc.ca.gov/proceedings/R0404025.htm>, and *Phase 1 Results: Establish the Value of Demand Response* (pp. 1) at <http://drcc.lbl.gov/pubs/60128.pdf>

⁶⁴ Demand Response Research Center. (April 2006). *Phase 1 Results: Establish the Value of Demand Response*. (pp. 1). San Francisco, CA: Author <http://drcc.lbl.gov/pubs/60128.pdf>

⁶⁵ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. Washington, DC: Author, pg. 72-73 <http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

⁶⁶ See California Public Utilities Proceeding R0701041 at http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64245.htm

In the meantime the cost-effectiveness tests outlined in the California Standard Practice Manual (SPM) – also known as the “California Tests” - are the closest thing to a standard cost-effectiveness test for demand response.⁶⁷ These tests include the Participant Test, the Ratepayer Impact Measure (RIM) Test, Utility Cost Test (UCT),⁶⁸ and the Total Resource Cost Test (TRC). Table 2-2 summarizes the metrics employed by each of the tests to express results. For a full description of the benefits and costs each of these tests is designed to measure, please see Appendix A.

Table 2-2 Cost-Effectiveness Test Metrics

Cost-Effectiveness Tests for Demand Response Programs		
Test	Primary Expression of Test Results	Secondary Expression of Test Results
Participant Test	Net Present Value (NPV) for all Participants	Discounted Payback Benefit-cost Ratio Per Participant NPV
Ratepayer Impact Measure (RIM) Test	Lifecycle Revenue Impact per Unit of Energy (kWh or therm) NPV	Lifecycle Revenue Impact per Unit of Energy (kWh or therm) Annual Revenue Impacts (by year, per kWh, kW, therm, or customer) First-Year Revenue Impacts (by year, per kWh, kW, therm, or customer) Benefit-cost Ratio
Utility Cost Test (UCT)	Net Present Value (NPV)	Benefit-cost Ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand)
Total Resource Cost Test (TRC)	Net Present Value (NPV)	Benefit-cost Ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)

Source: CALIFORNIA STANDARD PRACTICE MANUAL: ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

The SPM tests focus on avoided generation costs and are considered inadequate to capture the additional market and reliability benefits that demand response can bring to retail and wholesale markets.⁶⁹ In addition the relevance of standard cost-effectiveness tests for time differentiated tariffs (e.g. CPP and RTP) to motivate demand response has been disputed. This is because, unlike programs that provide direct incentives to customers to shift/reduce load, LSEs do not technically incur any costs by administering programs that rely on time differentiated tariffs.⁷⁰

⁶⁷ See *California Standard Practice Manual: Economic Analysis of Demand-Side Programs And Projects* (revised in 2001) found at www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

⁶⁸ Also know as the Program Administrator Cost (PAC) Test.

⁶⁹ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 72-73). Washington, DC: Author
<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

⁷⁰ Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author
<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

For the time being the SPM should be used as a proxy for a demand response cost-effectiveness test in the initial phases of designing a demand response pilot for the state of Michigan. Efforts should be made to monitor progress of CPUC Proceeding R.07-01-041 and DRRC's research initiative (due in early 2008) that address the metrics that should be considered and incorporated in any demand response/AMI pilot program.

2) Demand Response and Market Potential

A second concern in measuring the effectiveness of a demand response program is determining the potential level of customer participation and related load shifting and reduction.

The ability to communicate real prices and gauge customer responsiveness to price signals and other incentives is critical to the success a demand response program that relies on dynamic pricing to shift/reduce load. While the ability to forecast and understand how greater price-responsiveness will affect load shapes, load growth, and resource needs is still limited,⁷¹ a great deal of research has been conducted in this area.

Customers are most able to respond to prices when time-based rates are communicated to them, when they have load control systems that allow them to respond to price signals (e.g., by shedding load, automatically turning appliances down or off, or turning on an on-site generator), and when customers have meters that can measure consumption by at least the time of day, so the utility can determine how much power was used at what time and bill accordingly.⁷²

Experiences in New York, Georgia, California, and other states and pricing experiments have demonstrated that customers do take actions to adjust their consumption, and are responsive to price (i.e., they have a nonzero price elasticity of demand).⁷³ Customer price-responsiveness varies significantly by market segment among commercial and industrial users.⁷⁴ Just how much price-responsiveness can be expected from Michigan's industrial, commercial, and residential customer bases remains to be determined. In order to make this determination, a demand response market potential (DRMP) study should be conducted.

DRMP studies are typically undertaken by policymakers to determine the achievable market penetration, benefits, and costs of a policy or program (such as a ratepayer-funded energy efficiency program).⁷⁵ Demand response market potential is the amount of demand response, measured as short-term load reductions in response to high prices or incentive payment offerings, expected to be offered when market prices exceed baseline average prices.⁷⁶ Results of a DRMP can be expressed

⁷¹ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 130). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

⁷² Ibid., pp. 13

⁷³ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 13). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

⁷⁴ Ibid., pp. 14

⁷⁵ Goldman, C., Hopper, N., & Bharvirkar, R. (January 2007) *Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers: A Scoping Study*. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory

<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

⁷⁶ For Detroit Edison's service territory, this corresponds to prices that are greater than \$75/MW.

as the percentage reduction in market demand that can be expected at, for example, a price (or offered curtailment incentive) of \$100/MWh.

In conducting a DRMP study the company will be trying to estimate how much demand response is available and from what sources. As such a DRMP necessarily involves estimating two separate elements:

- Participation - the number of customers enrolling in programs or taking service on a dynamic pricing tariff. Participation should be thought of in terms of market penetration in a given year (or other relevant time period).
- Response - quantities of load reductions at times of high prices or when curtailment incentives are offered.

Approaches for getting this information include customer surveys,⁷⁷ benchmarking,⁷⁸ and measuring elasticity.⁷⁹

Methods of estimating DRMP vary by customer segment. For residential and small commercial direct load control programs, customer load impact estimates can be derived from bottom-up engineering approaches or statistical evaluations of samples of participating customers with appropriate metering. Estimating the load reductions of large commercial and industrial customer demand response options⁸⁰ can be achieved by measuring elasticity.⁸¹

Detroit Edison may consider pursuing the following⁸² methodology as part of any pilot program to estimate the DRMP for large commercial and industrial customers:

1. Establish study scope - identify target population and types of demand response options to consider.
 - The target population is typically defined by the type of customer (e.g., commercial, industrial, agricultural), and/or customer size thresholds (e.g., threshold peak demand level).
 - Different types of demand response options may induce different levels of demand response impacts among customers.
 - Certain types of demand response programs or tariffs are more appropriate for certain market structures than others.

⁷⁷ Surveys that ask utility customers about their expected actions if offered hypothetical demand response options and used to estimate market potential.

⁷⁸ Applying observed participation rates and load reductions among customers in other jurisdictions to the population of interest.

⁷⁹ This approach involves estimating price elasticities from the usage data of customers exposed to demand response programs and/or dynamic pricing tariffs. After determining an expected participation level, price elasticities are applied to the population of interest to estimate load impacts under an expected range of prices or level of financial incentives to curtail load.

⁸⁰ DR programs that rely on customer-initiated response to prices (e.g., hourly or critical-peak pricing) or curtailment incentives (e.g., short notice emergency program, price response event program).

⁸¹ The elasticity approach explicitly links response to prices and customer behavior. When demand models based upon economic theory are used to estimate elasticities, they also enable the translation of experience from other jurisdictions with adjustments for differences in customer- and market-specific factors.

⁸² Goldman, C., Hopper, N., & Bharvirkar, R. (January 2007) *Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers: A Scoping Study*. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory

<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

2. Customer segmentation - identify customer market segments.

- Identify customer market segments that are expected to respond in similar ways,⁸³ or that could be approached with specific marketing strategies or program designs.
- Business activity for large commercial and industrial customers is often strongly correlated with both willingness to participate in demand response programs (or remain on default-service hourly pricing), and willingness and ability to respond to high-price or reliability events by temporarily lowering demand.⁸⁴ As such, partitioning these customers by business segment may be a good course of action to pursue.
- Segments should be refined enough to capture significant trends in customer willingness to participate in and respond to demand response programs or dynamic pricing tariffs.

3. Estimate net program penetration rates - use available data to estimate current customer enrollment in voluntary programs and exposure to default pricing programs. See Appendix B for more on methods of estimating demand response penetration rates.

4. Estimate price response - develop elasticity estimates for various demand response options, customer market segments, and factors found to influence price response. See Appendix C for more on factors that influence customer response to demand response programs.

5. Estimate load impacts - use information from steps 2 to 4 to estimate the amount of demand response that can be expected from the target customer population at the utility at reference price (or incentive level).

See Appendix D for a schematic representation of the framework (laid out in steps 1 through 5) for estimating demand response market potential among large C&I customers in a given jurisdiction or utility service territory.

3) Measuring Avoided Demand (M&V)

Another concern in determining the effectiveness of a demand response program is the need to measure and verify (M&V) avoided demand. That is, the merit of a demand response program is closely related to the extent to which avoided demand can be accurately measured, attributed to the demand response solution, and validated as a reliable demand response resource (DRR). M&V standards should: (1) provide market participants with confidence in the accuracy and precision of reported MWh reductions from demand resources; (2) provide demand resource suppliers with reasonable and clear requirements; and (3) be comparable to the M&V requirements of traditional supply resources (to the greatest extent possible).

The measurement of demand reductions associated with incentive-based demand response programs has proven to be a difficult and controversial problem.⁸⁵ Calculation of demand-response impacts is presently based on a combination of direct measurements, statistical estimation and engineering

⁸³ That is, the segmentation of customers groups should be refined enough so as to trends in customer willingness to participate in and respond to demand response programs or dynamic pricing tariffs.

⁸⁴ Goldman, C., Hopper, N., & Bharvirkar, R. (January 2007) *Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers: A Scoping Study*. Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory
<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

⁸⁵ Particularly for demand-bidding, emergency demand response, and capacity programs.

analysis. Calculating the level of consumption that would have occurred if a customer had not curtailed consumption (i.e., the customer's baseline) has proven to be a key measurement issue. While utilities and ISOs employ a variety of ways to estimate baseline consumption⁸⁶ there does not appear to be any consistency in these methods across utilities, states, and ISOs.⁸⁷ Some ISOs use an average usage over a set number of days, while others use the average of consumption immediately prior to and after demand-response events.⁸⁸

Until recently lack of real-time customer-level load data has also been a barrier to the establishment of M&V methodologies that provide credible measurements. For instance, a key problem with most estimation methods is the potential for gaming – participants may bid into the market or state that they will curtail when they would already be shut down for the day. The ultimate solution for this measurement problem would be to directly measure usage in real-time or to set specific entitlements or reduction levels, instead of after-the-fact measurement and estimation.⁸⁹

All large industrial clients served by Detroit Edison have Interval Demand Recorder (IDR) enabled metering which allows the company to measure and verify curtailment activity. Other challenges related to establishing customer baseline measures and gaining real-time load data are now being addressed by the installation of an automated metering infrastructure (AMI) and other enabling technologies.

The most efficient way to meet load-shedding goals is to employ demand response programs with mass appeal and/or large customer appeal.

Given an active load research function and the ability to collect interval data, there is a relatively low cost to implementing M&V methodologies. According to Detroit Edison's Load Research group, costs of M&V are roughly 5 to 10% of program savings.

Detroit Edison's Load Research group has been collaborating with the Demand Response Resource Center (DRRC) as part of an effort to set national M&V standards.

III. Summary

There are many demand response options for Detroit Edison to experiment with. Calculating the effectiveness of a demand response program is based on a combination of statistical estimation and engineering analysis. Currently there is no consistency in these methods across utilities, states, and

⁸⁶ A review of baseline methods can be found in Xenergy, "Protocol Development for Demand Response Calculation," prepared for the California Energy Commission, Contract 400-28-002, August 2002. In addition, ISOs have begun to publish their own M&V guidelines. For instance the ISO New England published its "Manual for Measurement and Verification of Demand Reduction Value from Demand Resources Manual M-MVDR" in April 2007.

⁸⁷ M&V Standards are based on the following documents: ISO New England's Operating Procedure; ISO New England's M-LRP Version 9.0; International Performance Measurement and Verification Protocol (IPMVP) 2002 Version; California Energy Efficiency Evaluation Protocols: Technical, Methodological, and Reporting Requirements for Evaluation Professionals (April 2006); 2000 Federal Energy Management Program (FEMP) Measurement and Verification Guidelines; California Standards for Validating, Editing and Estimating Monthly and Interval Data (source: "Demand Resources Measurement & Verification Standards Manual Overview," ISO-New England 1/3/07 presentation)

⁸⁸ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 130). Washington, DC: Author

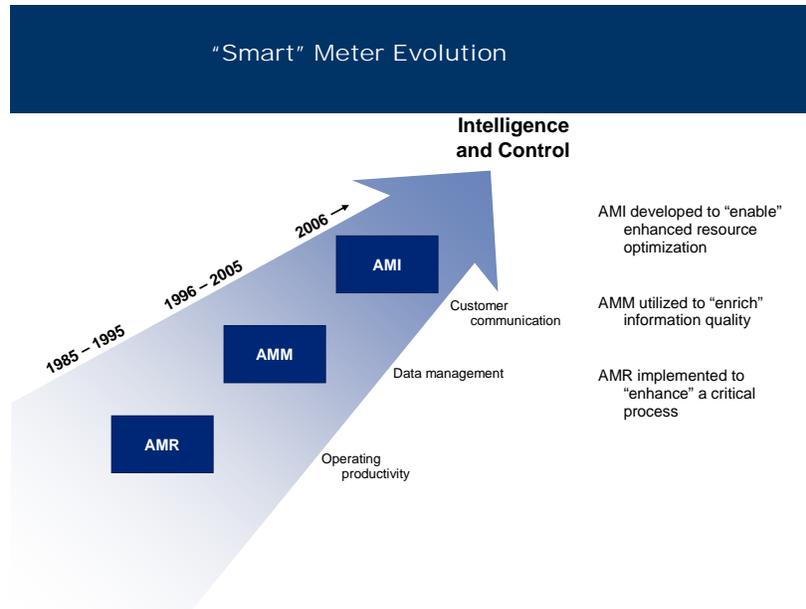
<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

⁸⁹ Ibid.

ISOs. In its drive to develop a robust demand response portfolio Detroit Edison will need to work with state regulators and other LSEs to settle on common standards for measuring the effectiveness of future demand response programs in the state.

SECTION 3: ADVANCED METERING AND DEMAND RESPONSE

Metering has undergone a transformation over the last two decades, with many utilities decommissioning their electromechanical meters in favor of solid state, electronic meters. Along with the shift towards solid state meters, there has also a move from manual meter reading to automated meter reading (AMR), from AMR to advanced metering management (AMM), and from AMM onto advanced metering infrastructure (AMI).⁹⁰ While additional functionality has driven some of the shift towards electronic meters, investments in AMR and AMI account for the majority of the shift.⁹¹



Source: Booz | Allen | Hamilton

This new generation of meters is part of a surge in demand response enabling technologies, which include enterprise energy management systems, energy management and control systems, wireless mesh networks, and on-site generation technologies.⁹²

Table 3-1 describes national advanced metering market drivers for the next five years.

⁹⁰ “Advanced Metering Infrastructure,” Wikipedia
http://en.wikipedia.org/wiki/Advanced_Metering_Infrastructure

⁹¹ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 35).

⁹² Ibid., pp. 33

Table 3-1 Advanced Metering Market Drivers

Rank	Driver	1-2 Years	3-4 Years	5-7 Years
1	Energy Policy Act of 2005	High	High	High
2	Changing Mindset of Utilities	Medium	Medium	Medium
3	Reduced Operational Costs of Next Generation AMR	Medium	Medium	Medium
4	Improved Accuracy of AMR System	Medium	Medium	Low
5	Improved Load Forecasting Using AMR Data	Medium	Medium	Low
6	Better Outage Management	Medium	Medium	Low
7	Better Utilization of Human Resources	Medium	Medium	Low
8	Successful Implementation In Diverse Conditions	Medium	Medium	Low
9	Retaining Large-Customers Has Become Top-Priority	Medium	Low	Low

Source: Frost & Sullivan

A 2007 survey conducted by KEMA, Inc. revealed that the top three drivers for the fourteen leading U.S. utilities⁹³ are: (1) regulatory directives/mandates, (2) desire for customer service enhancements, and (3) desire for greater operational efficiencies.⁹⁴

Adoption of advanced metering by Detroit Edison has been driven mainly by the prospects of reduced operational costs, improved accuracy, and better outage management.

Nationwide overall utility operational costs have dropped dramatically with the implementation of basic and advanced metering systems. Over the next five years smart metering systems are expected to save up to 50% in meter reading costs (both regular and off-cycle reads), while still remaining cost-effective. These systems also enable TOU programs and demand data, as stipulated by EPACT 2005.⁹⁵

I. AMR Market

At the start of the 21st century many electric utilities, no longer seen as a safe investment due to faltering ventures into non-regulated businesses, experienced a decline in investor interest.⁹⁶ Under pressure to cut costs while improving efficiencies, utilities turned to automated meter reading (AMR) systems - systems that allow meters to be read remotely - as one of the best investments to reduce costs.⁹⁷ The major cost savings expected from AMR systems were determined to derive from reliability improvements resulting in reduced maintenance, reduced meter reading personnel and cash flow improvements.⁹⁸ The revenues for the AMR segment of the metering market were estimated to be \$548.6 million in 2005.⁹⁹

⁹³ Including Baltimore Gas & Electric, CenterPoint Energy, Consolidated Edison, DTE Energy, PEPCO/Delmarva, Pacific Gas & Electric, Portland General Electric, San Diego Gas & Electric, Seattle City Light, Southern California Edison, Southern Company, TXU, WE Energies, and Xcel Energy.

⁹⁴ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007, from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

⁹⁵ Frost&Sullivan, Energy & Power Systems Report. (January 2006). *North American Automated Meter Reading Markets*.

⁹⁶ Ibid.

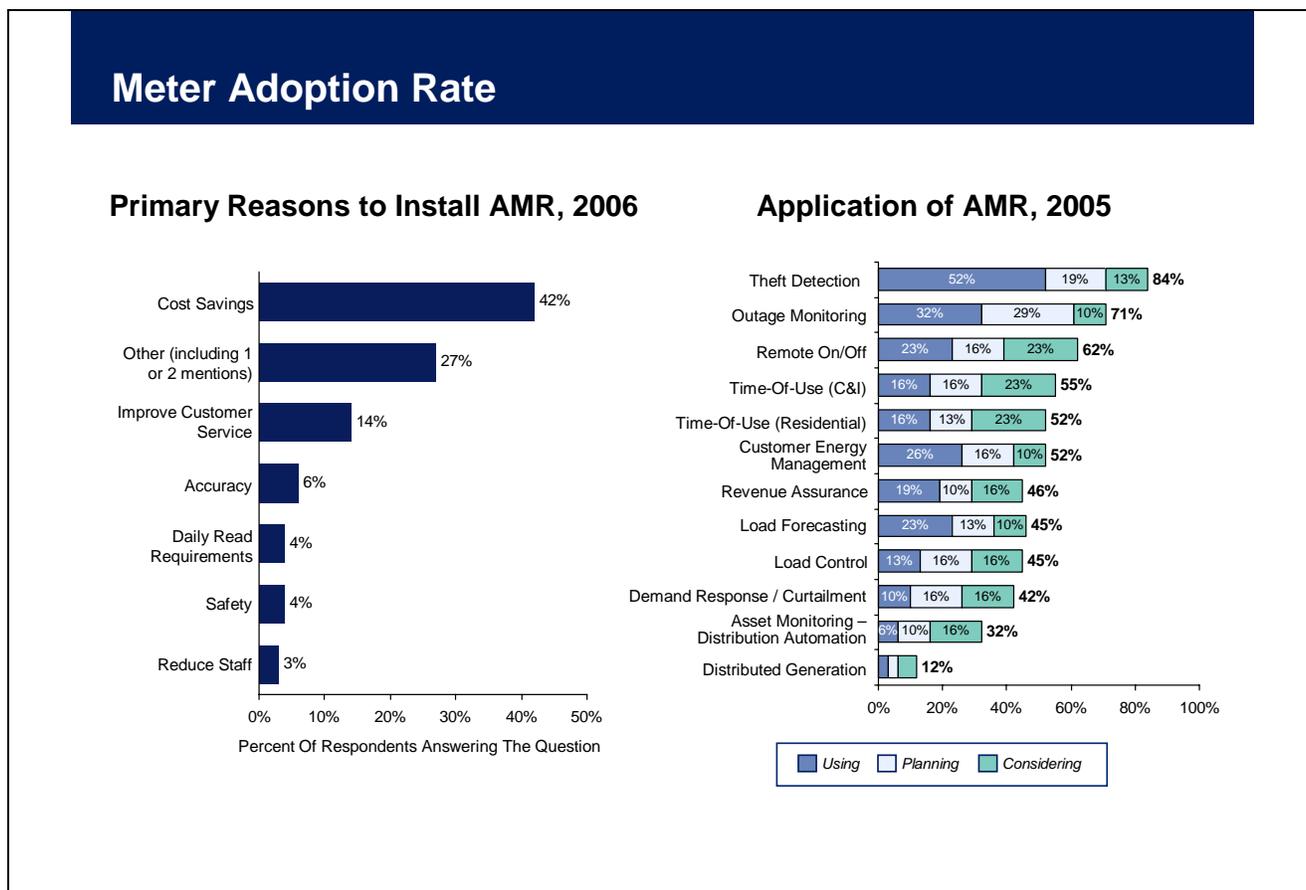
⁹⁷ Frost&Sullivan, Energy & Power Systems Report. (January 2006). *North American Automated Meter Reading Markets*.

⁹⁸ Ibid.

⁹⁹ Frost&Sullivan, Energy & Power Systems Report. (January 2006). *North American Automated Meter Reading Markets*.

Chart 3-1 shows the results of Chartwell Annual Utilities Survey of the uses of AMR by utilities and ISOs in 2005-06.

Chart 3-1 Uses of AMR by Utilities and ISOs, 2005-06



Source: Chartwell Annual Utilities Survey

II. Growth in AMI Market and “Smart” Meters

According to some projections, the North American AMI market will grow about 20% annually through 2010.¹⁰⁰ To date AMI (or related SmartGrid initiatives) have not been implemented on a large scale in the United States. For instance, results of a 2005 FERC survey indicate that AMI currently has a low market penetration of 5.9% in the United States.¹⁰¹ As of August 2006 AMI penetration in Michigan was much less than the national average, with just 0.6% of meters being AMI (29,065 AMI meters, out of the more than 4,694,569 electric meters in the state).¹⁰² Although

¹⁰⁰ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007, from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486. Also See Appendix C for a listing key AMI organizations and vendors.

¹⁰¹ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 26). Washington, DC: Author
<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

¹⁰² *Ibid.*, pp. 30

in many ways AMI technologies are maturing, they can hardly be characterized as being fully mature at this point.¹⁰³

Yet while concerns about inadequate technologies and customer interest linger, a significant number of utilities are moving aggressively towards developing AMI/Smart Grid strategies. Executives at many utilities believe the technology has evolved sufficiently to make it reasonably priced and worth the utility cost exposure.¹⁰⁴ The increasing cost of electricity and energy efficiency are also forcing many utilities to look at the impact of not developing TOU rates or other demand response/energy efficient programs that AMI technology enables.¹⁰⁵

AMI Deployment and Technology

A 2007 survey of fourteen leading utilities¹⁰⁶ conducted by KEMA, Inc. revealed that the average length of an AMI deployment project is 5.7 years, the average number of AMI electric meters deployed is 2.2 million, and the average length of pilot programs is 9 months.¹⁰⁷

An AMI system consists of various components¹⁰⁸ and adds value primarily by enabling two-way communication between customers and utilities.

AMI is designed for meter reading, outage monitoring and response, power quality measurement, remote disconnect/reconnect, system management, and distribution asset optimization and design. AMI also facilitates multiple, user-friendly communications pathways that send price signals and notify customers of load curtailments events, thus incentivizing customers to limit usage during critical periods.

AMI also opens up the potential for direct communications with devices (such as communicating programmable thermostats, aka “smart thermostats”) that facilitate demand response. For instance AMI contains energy information tools that enable near real-time access to interval load data, thus linking customer utility bills to wholesale market prices (and allowing consumers to benefit from curtailment during times of peak demand). California’s statewide pricing program (SPP) demonstrated that residential consumers exhibit greater price responsiveness when they used enabling equipment; in fact the users had an average 27% reduction in critical peak load, more than twice those without automated equipment. Furthermore, 60% of the responsiveness has been attributed to the devices, and the remaining 40% to price signals to the consumers.¹⁰⁹

¹⁰³ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007 from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

¹⁰⁴ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007 from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

¹⁰⁵ Ibid.

¹⁰⁶ Including Baltimore Gas & Electric, CenterPoint Energy, Consolidated Edison, DTE Energy, PEPCO/Delmarva, Pacific Gas & Electric, Portland General Electric, San Diego Gas & Electric, Seattle City Light, Southern California Edison, Southern Company, TXU, WE Energies, and Xcel Energy.

¹⁰⁷ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007, from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

¹⁰⁸ Including meters enabled for two-way communication, a data collection network, and a host system/database.

¹⁰⁹ Stanford University, Precourt Institute for Energy Efficiency. (2006). *Demand Side Management*. Retrieved July 2007 from http://piee.stanford.edu/cgi-bin/html/research_demand.php

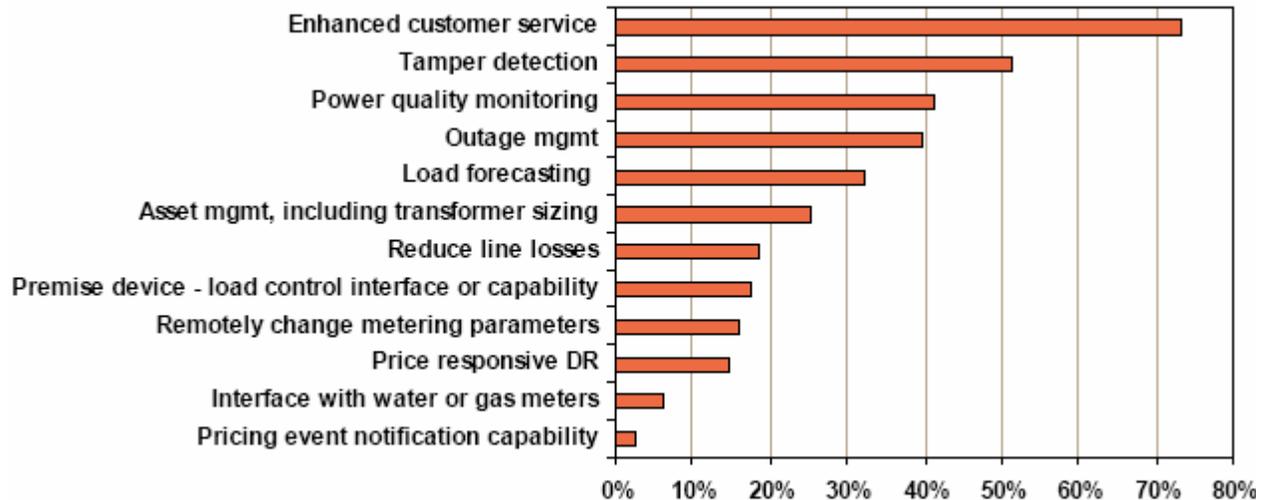
Lastly AMI facilitates the analysis of load curtailment performance relative to customer baseline, making measurement and verification (M&V) a real possibility for Load Research groups, such as Detroit Edison's, that are skilled at such measurements.

AMI's two-way digital communication and related functionalities can ultimately change the shape of the load curve during critical periods.

Uses and Benefits of AMI

Chart 3-2 shows the results FERC's 2005 Survey into the uses of AMI by utilities and ISOs. The most often reported function was "enhanced customer service," and the least often reported was "pricing event notification capability." Other uses that received a relatively high percentage of usage were tamper detection and power quality monitoring.¹¹⁰

Chart 3-2 Reported Uses of AMI Systems



Source: FERC

Table 3-2 highlights some of the key benefits provided by AMI, and table 3-3 offers a comparison of AMI to manual and AMR functionalities.

¹¹⁰ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 31). Washington, DC: Author
<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

Table 3-2 Key Benefits of AMI to Utilities

Benefits	Details
Increased accuracy of, and accessibility to meter reads	AMI eliminates manual meter reading and all related accuracy and access issues including (a) inaccurate and estimated bills, (b) property access difficulties, (c) electromechanical meter accuracy issues if SS meter deployed with AMI
Improved quality and reliability of energy delivery	AMI provides remote monitoring of the distribution network and enables (a) improved load forecasting, (b) faster and more reliable outage detection and restoration, (c) more efficient and informed planning of distribution assets, and (d) enhanced transformer load management
Timely, accurate, and effective customer care	AMI improves relationships with the customer and PSC in that it (a) addresses customers' questions and requests promptly and accurately, (b) improves customer service, and (c) reduces customer complaints
Collection and theft process efficiency	AMI enhances the collection and theft processes thru (a) the elimination of final estimated reads, (b) enhanced meter tampering detection, and (c) remote disconnect/reconnect capabilities
Accurate demand and consumption tracking	AMI enables customers to track their consumption and demand over the web and assist them with (a) adjusting their consumption according to their budgets, and (b) choosing a more convenient billing cycle to meet their income
Communication with complimentary devices/appliances	AMI further facilitates demand response by coordinating load management with smart thermostat, onsite generators, energy management systems and other devices

Table 3-3 Comparison of AMI to manual and AMR functionalities

System Feature or Element	Manual 	Automatic Meter Reading (AMR)	Advanced Meter Intelligence (AMI) 
Meters	Electromechanical	Hybrid	Hybrid or solid-state
Data Collection	Manual, monthly	Drive by, monthly	Remote via communications network, daily or more often
Data Recording	Total consumption	Total consumption	Time-based (usage each hour or more often)
Primary Application	Total consumption billing	Total consumption billing	Pricing, Customer options Utility operations Emergency DR KW, KVAR
Key Software Interface	Billing and Customer Information System	Billing and Customer Information System	MDM Billing, customer info system Outage management Emergency DR
Additional Devices Enabled	None	None	Smart thermostats In-home displays Appliance controllers

Source: Own analysis and “AMI: Overview of System Features and Capabilities,” eMeter Corporation

A distinction between a standard AMI meters and “smart” meters should be made. A smart meter generally refers to a type of AMI meter that does more than facilitate two-way metering communications. Smart meters also enable communication between the meter and “smart appliances,”¹¹¹ thus giving utilities and consumers the ability to automate demand response.

III. AMI Data Collection

AMI data collection is typically done by means of a fixed communication network. A 2007 survey of fourteen leading utilities¹¹² conducted by KEMA, Inc. revealed that utilities appear to be choosing different data collection technologies based on their specific requirements and geography characteristics.¹¹³ Utility utilized communication networks include fixed radio frequency (RF), powerline carrier (PLC), and public networks (landlines, cellular, or paging).¹¹⁴

¹¹¹ For more about *smart appliances* see “Autonomous Home Monitoring and Control” section below.

¹¹² Including Baltimore Gas & Electric, CenterPoint Energy, Consolidated Edison, DTE Energy, PEPSCO/Delmarva, Pacific Gas & Electric, Portland General Electric, San Diego Gas & Electric, Seattle City Light, Southern California Edison, Southern Company, TXU, WE Energies, and Xcel Energy.

¹¹³ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007, from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

¹¹⁴ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 36)

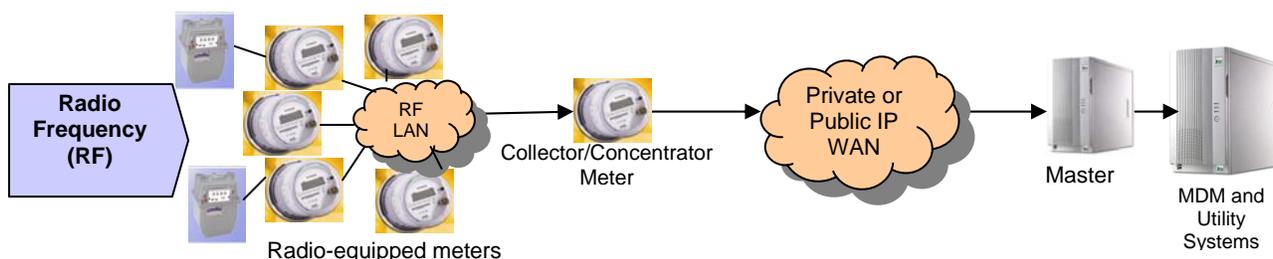
Many utilities are looking to industry standards before selecting an AMI data collection technology solution. Many of the utilities participating in the KEMA, Inc survey, for instance, indicated an intention to wait for an announcement later this year from the American National Standards Institute (ANSI) about a new standard (C.12.22) that provides an application layer standard for network communications. This standard is designed to transport C.12.19 standard data tables in electric metering over any physical medium.¹¹⁵ The open protocol in the ANSI C.12.22 standard will provide the same opportunity for meter communications over various networks, enabling each endpoint to communicate meter data in a similar manner.

See Appendix E for a listing of AMI data collection technologies and vendors selected by utilities participating in 2007 KEMA, Inc. Survey.¹¹⁶

RF

In a basic RF system meters may communicate over a private network using RF signals. Individual meters communicate their readings to a data collector or a repeater, which in turn forwards the information to a data collector. Data collectors store the meter reading information until it is uploaded to the AMI host system at a preset time. Communications between the data collector and network are generally two-way, and may occur over a public network, via microwave, or an ethernet connection.¹¹⁷

Basic RF System



Source: DTE AMI Project Overview, Communication Pack 6/25/07

The KEMA, Inc. survey revealed that RF appears to be the dominant choice for the utilities, though it is often used in combination with BPL or PLC interfaces.¹¹⁸ For instance, RF is planned to support AMI Systems at Con Edison, Pacific Gas & Electric, Southern California Edison, and Xcel Energy. PG&E plans to use PLC technology to retrieve meter data and a fixed RF network for collecting and transmitting daily gas usage data. PG&E has opted to use a wide area network to control and manage interval data transmitted to its information systems for billing and customer viewing. Portland General Electric plans a similar approach.¹¹⁹

Wireless mesh technology – a relatively new version of RF that allows meters to pass along reads from other meters – is gaining widespread significance in part due to its ability to incorporate high

¹¹⁵ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007, from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

¹¹⁶ Also see Appendix F for list of key AMI organizations, and Appendix G for AMI project costs for nine of the fourteen utilities participating in the 2007 KEMA, Inc. survey.

¹¹⁷ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 37)

¹¹⁸ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007, from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

¹¹⁹ Ibid.

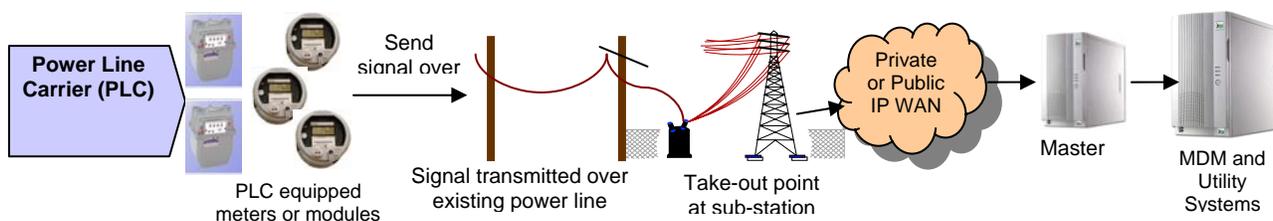
functionality at lower risks and competitive costs. It also appears to be better suited for some urban areas than traditional RF-configured systems that typically allow meters to report to only one collector point.¹²⁰

PLC

For much of their history PLC devices operated on frequencies below 2MHz and had relatively limited communication capabilities. The development of sophisticated modulation schemes and faster digital processing capabilities has produced new designs that surmount past technical obstacles. These new designs have led to the growth of broadband over powerline (BPL) systems that couple radio frequency (RF) energy onto the existing electric powerlines to provide high-speed communications capabilities¹²¹

High-speed BPL is likely to supplant PLC and be used by utilities to add intelligent networking capabilities to the electric grid. BLP technology will allow network addressable and interconnected BLP components to work together to improve the efficiency of energy management activities, power outage notification and automated meter reading.¹²²

Basic PCL System



Source: DTE AMI Project Overview, Communication Pack 6/25/07

Public Networks

Some AMI systems rely on existing public networks to supply communication between meters and utilities. Public networks may include internet, paging, satellite, and/or telephony (cellular or landline).¹²³

A key advantage to using public networks is that they give utilities the ability to deploy AMI across a wide area with low densities. In addition, because utilities do not have to invest in building a private infrastructure, utilizing public networks may present lower upfront costs and may facilitate much faster deployment.¹²⁴

¹²⁰ McNamara, W. (May 2007). *Many Utilities Starting to Develop AMI and Utility-of-the-Future Strategies-Part 1*. Retrieved July 2007, from http://www.energypulse.net/centers/article/article_display.cfm?a_id=1486

¹²¹ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 36)

¹²² *Ibid.*, pp. 37

¹²³ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 38)

¹²⁴ If there is coverage at the customer's location then installation costs are limited to installing the new endpoint and setting up the service. See *The Role of Enabling Technologies in Demand Response* (pp. 39) for more information.

Key limitations to using public networks include: (a) being subject to coverage provided by the public network, (b) being dependent on changing communication protocols,¹²⁵ and (c) being subject to high operating costs.

IV. Meter Data Management

A meter data management (MDM) system is a key component of advanced metering and central to the capturing of the key benefits to be derived from advanced metering. An MDM system provides a database repository that automates and streamlines the complex process of collecting meter data from multiple collection technologies and delivers the data in an appropriate format to a utility billing system.¹²⁶

Balancing supply and demand is crucial to maintaining a reliable and stable energy delivery system. By applying advanced statistical modeling to historic data stored in MDM systems, utilities can generate highly accurate forecasts of future energy demand. This is beneficial to utilities, as accurate forecasts remove the guesswork from daily operations and long-term planning, which in turn lower risks and costs.¹²⁷ With the ability to predict times of peak demand, utilities and their customers can form partnerships to reduce extreme loads and thus maintaining a reliable and affordable supply of power.¹²⁸

V. Technologies Enabled By AMI

As previously described, smart meters give utilities the ability to establish a two-way, dynamic communications path with their customers, enabling the utility to better understand its operations and quality of delivery to customers. Smart meters also provide means to communicate account energy use characteristics to customers and enhance their understanding of the drivers behind their own electricity costs.

A smart meter network, however, is but the first step in what will one day be a much richer interaction between the utility and its customers.¹²⁹ Regulators in many countries are looking “beyond the meter” to devices in the consumer’s home that both provide the consumer a real-time view of their consumption and change their behavior to facilitate energy conservation and demand response programs.¹³⁰

In addition, smart meters open up opportunities for innovation among large commercial and industrial customers. Complimentary technologies, such as smart thermostat, onsite generators, energy management systems, home network, and in-home services facilitate demand response by (1) communicating price signals and (2) automating customer response.¹³¹

Residential Consumers and Home Networks

¹²⁵ Especially true in the cellular segment.

¹²⁶ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 39)

¹²⁷ *Ibid.*, pp. 40

¹²⁸ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 40)

¹²⁹ Lund, J. (2007). The Next Innovation in Energy Efficiency - Extending Advanced Metering into the Home.

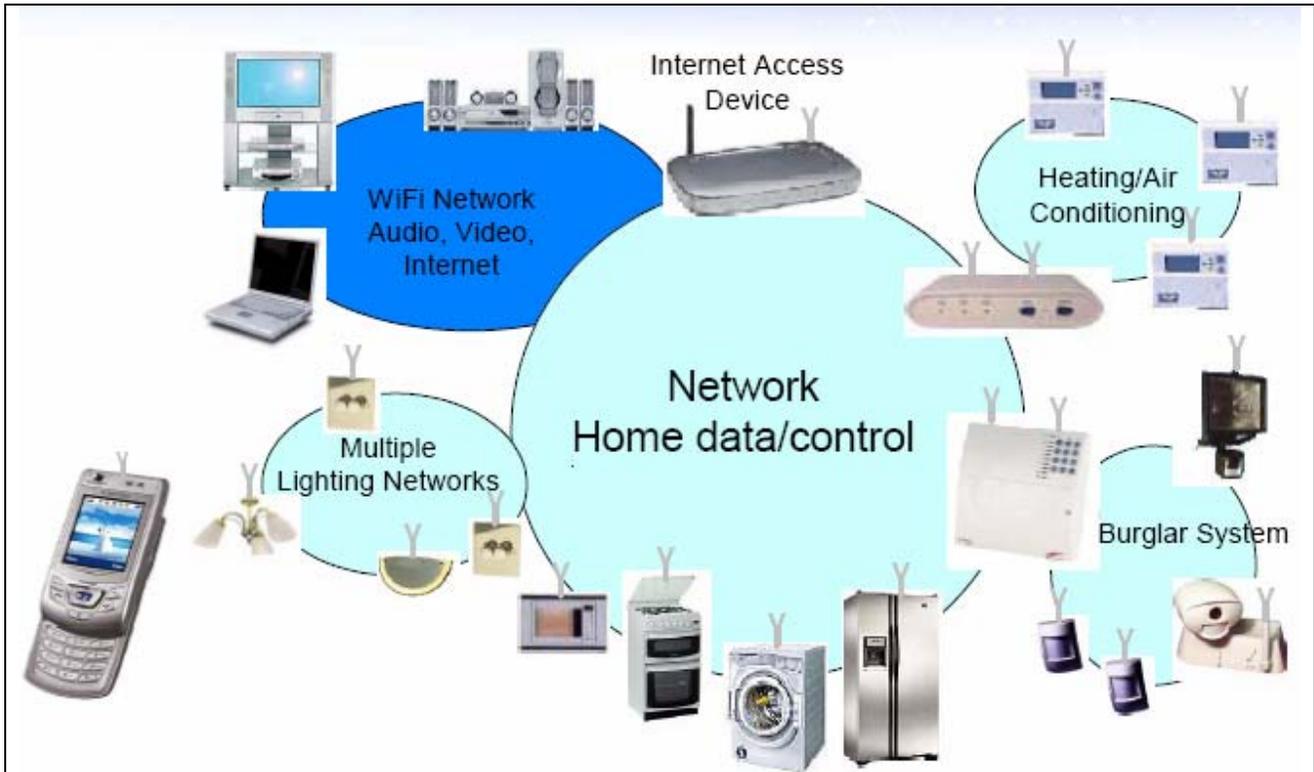
Energycentral.com. Retrieved July 2007 from

<http://topics.energycentral.com/centers/datamanager/view/detail.cfm?aid=1515>

¹³⁰ *Ibid.*

¹³¹ Research Reports International (May 2007). *The Role of Enabling Technologies in Demand Response*. (pp. 40)

Home networks have the potential to become important components of demand response initiatives. These networks include both intelligent equipment and control mechanisms, and the basic communication system to the end-user. The system could include an automated thermostat or advanced home control center, capable of providing significant savings during peak hours.¹³²



Source: Jennic Wireless Microcontrollers

The use of AMI in conjunction with home networks is growing in popularity. In the UK, for example, regulators and utilities have proposed that consumers be provided with a free in-home display device that shows how much electricity is being used in their home at any specific time. Today, several products on the market use clamp-on current transformers to monitor consumption and transmit this information to a wireless display. These first-generation systems hint at what will be possible with a true smart metering system. These displays are limited by the connection to today’s “dumb” meters to creating their own version of consumption information. They do not have access to the actual billing-grade information from the meter, nor do they have access to information about the tariff structure. Yet as smart meter networks enable consumers to download new rate plans into their meters, the ability to interact with the meter becomes critical to give consumers a true picture of their current consumption and its impact on their ultimate bill.¹³³

¹³² Stanford University, Precourt Institute for Energy Efficiency. (2006). *Demand Side Management*. Retrieved July 2007, from http://piee.stanford.edu/cgi-bin/htm/research_demand.php

¹³³ Lund, J. (2007). The Next Innovation in Energy Efficiency - Extending Advanced Metering into the Home. *Energycentral.com*. Retrieved July 2007 from <http://topics.energycentral.com/centers/datamanager/view/detail.cfm?aid=1515>

Autonomous Home Monitoring and Control

The connection to a display, however, is just the first step. Recent advancements in home networking technologies, such as the recent ratification of the low-power ZigBee¹³⁴ wireless protocol, and the steady progress in the development of electronic components and devices, have created a rich environment for researching and ushering in new solutions for demand response enabled, and energy efficient, homes and appliances.¹³⁵

While a display has the benefit of giving the consumer easy access to a view of their whole-home consumption, it does not provide consumers with any details on *where* energy is being consumed, *only how much* in aggregate. To gain insight about the consumption of individual devices some form of sub metering is required. Devices that support this level of functionality and control are beginning to become available. Companies such as those in the Digital Home® Alliance¹³⁶ are delivering standards-based home control solutions that are as easy to install as simply plugging into an outlet. Smart wall modules can measure how much energy a single product or a group of products use in a home, and then send the data to an in-home display or computer for analysis. These wall modules can, for example, help consumers find out how much it costs to run their refrigerator. They can also show them how much energy their television or computer uses in “sleep” mode -- information that just might cause them to shut those products off more often.¹³⁷

“Smart appliances” also promise to play a significant role in finding new ways to create demand response enabled homes. Smart appliances are traditional home accessories - blenders, refrigerators, even alarm clocks - enhanced with computer chips to enable new features.¹³⁸ The fast growing \$37.7 billion dollar worldwide building control systems market is full of companies that are developing standards and technologies to enable smart appliances and other products to communicate with one another in networks that set themselves up automatically. Research into the next wave of products is being done by the Internet Home Alliance, a consortium that includes IBM, Microsoft, Panasonic and other major corporations. Other companies are developing similar kinds of devices.¹³⁹

Many of the devices available today are smart, but solitary. They cannot communicate with other smart appliances. Appliances with enhanced IQs that are on the market now include:

¹³⁴ ZigBee® is a low-power, short-distance wireless home area network (HAN) protocol that has great possibilities in applications from home automation to industrial control. ZigBee is a wireless standard based on 802.15.4 that was developed to address the unique needs of most wireless sensing and control applications. These applications are typically low duty cycle, low data rate and have low power requirements - where battery life is measured not in hours, days or weeks, but in years.

¹³⁵ Stanford University, Precourt Institute for Energy Efficiency. (2006). *Demand Side Management*. Retrieved July 2007, from http://piee.stanford.edu/cgi-bin/htm/research_demand.php

¹³⁶ See <http://www.digihome.org/overview.htm>

¹³⁷ Lund, J. (2007). The Next Innovation in Energy Efficiency - Extending Advanced Metering into the Home. *Energycentral.com*. Retrieved July 2007 from <http://topics.energycentral.com/centers/datamanager/view/detail.cfm?aid=1515>

¹³⁸ Ibid.

¹³⁹ Lund, J. (2007). The Next Innovation in Energy Efficiency - Extending Advanced Metering into the Home. *Energycentral.com*. Retrieved July 2007 from <http://topics.energycentral.com/centers/datamanager/view/detail.cfm?aid=1515>

- Washers and dryers from several manufacturers that use computer processors and other innovations to simplify laundry day, conserve water and electricity, and reduce wear and tear on clothing.
- Kitchen range by Whirlpool that can be programmed to automatically refrigerate uncooked lasagna while a customer is at work, then turn itself on and bake its content by the time the customer returns home.
- Several companies have produced internet refrigerators - home computing hubs complete with touch-screen monitors to access news, e-mail or recipes and assist with shopping lists and sometimes the shopping itself, using the Internet.

Automating Demand Response

Smart appliances and information alone, however, will not have a significant impact on supply and demand imbalances, or reduce load during peak demand. Likewise it is unreasonable to believe that the average home-owner has the technical capabilities to manage home responses to short-term pricing signals, unless the response is very user friendly and does not require frequent monitoring.¹⁴⁰ And once the initial novelties of alerts and messages from utilities have worn off, and the easy changes to consumption patterns are made, the display may become an item that is consulted only occasionally.

In short, it may take more than variable tariffs and messages sent to a display to get “consumer response” in times of peak demand. Indeed in-home devices that act autonomously on the customer’s behalf may be required. *By incorporating information from a smart meter, smart appliances can react automatically to changing energy-rate information.*

The ability to deploy, at reasonable cost, a network of sensors (and actuators) along with the development of cheap, small, high power processors, raises the possibility that “smart buildings” - buildings that can sense the indoor environment, gather information about the economic parameters including the real-time price of electricity, and optimally control the appliances, including the HVAC systems, within the building – will become a reality in the near future. The networks in smart buildings will be able to apply transactive control techniques to manage the energy consumption of the household according to defined settings and environmental conditions. A network could include enough automation that it removes the burden of coping with volatile energy prices from the end-user.¹⁴¹ Air conditioning, heat, hot water, and clothes drying account for about 80% of the electrical demand in a typical residential home; such devices may be monitored and controlled by the system. Soon, instead of running a dishwasher mid-day when electricity rates are higher, a service application will either automatically delay the machine until a lower rate period -- or let the consumer choose when to operate it.¹⁴²

¹⁴⁰ For instance, one California estimate says that one out of four homeowners has at least one programmable thermostat, yet only 20 percent of those owners use the programming features.

¹⁴¹ Stanford University, Precourt Institute for Energy Efficiency. (2006). *Demand Side Management*. Retrieved July 2007, from http://piee.stanford.edu/cgi-bin/htm/research_demand.php

¹⁴² Lund, J. (2007). The Next Innovation in Energy Efficiency - Extending Advanced Metering into the Home. *Energycentral.com*. Retrieved July 2007 from <http://topics.energycentral.com/centers/datamanager/view/detail.cfm?aid=1515>

Table 3-4 describes some of the key existing and emerging home network and smart building technologies.

Table 3-4 AMI and Smart Appliances Technology Landscape

<p>Existing Technologies</p> <p><u>Energy controls</u></p> <ul style="list-style-type: none"> • Programmable thermostats • Remote A/C compressor control • Remote water heater control • Residential Time-of-Use meters • Smart panel • User interface • Utility/Customer interface • Smart Windows <p><u>Energy storage technologies</u></p> <ul style="list-style-type: none"> • Batteries • Ice storage • Thermal storage 	<p>Emerging Technologies</p> <p><u>Energy controls</u></p> <ul style="list-style-type: none"> • Programmable communicating thermostats linked to the Internet • Automated metering infrastructure • Smart interactive panels • Smart appliances • “Black box” appliance-level or panel level switch • Utility/customer interface – load curve operates appliances <p><u>Energy storage technologies</u></p> <ul style="list-style-type: none"> • Flywheels • Advanced batteries
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Source: Role of Demand Response and Demand Reduction in Energy Purchasing Strategy (SEE <http://energy2006.net/presentations/jose-luiscontreras.pdf>)

VI. Summary

AMI technology promises to provide essential analytical tools that will greatly enhance the ability to execute demand response programs. Many issues surrounding AMI standards, costs, and benefits remain unresolved. Finding innovative ways of leveraging AMI technology to automate demand response is key to AMI’s future as an enabler of demand response.

SECTION 4: MICHIGAN NEEDS ANALYSIS

Fitting demand response solutions to customer energy-use habits and needs is a necessary part of the development of a successful demand response program.

I. Michigan's Demand Response Stakeholders

The groups of individuals with a stake in the outcome of any demand response program initiated in Michigan are (1) electricity customers (residential, commercial, industrial), (2) the MPSC, (3) the alternative retail electricity suppliers (AESs), (4) MISO, and (5) Detroit Edison, Consumers Energy (Consumers), and all other load serving utilities participating in Michigan's Demand Response Collaborative.

II. Customer Energy-Use Patterns

As of 2005, the number of consumers Detroit Edison served, sales (megawatthours), by sector:

Sector	Number of Consumers	Revenue (thousand dollars)	Sales (megawatthours)
Residential	1,977,013	1,452,113	16,811,958
Commercial	178,296	1,265,007	15,618,132
Industrial	905	655,672	12,316,774
Total	2,156,214	3,372,792	44,746,864

Source: Energy Information Administration ("Electric Sales, Revenue, and Price 2005")
http://www.eia.doe.gov/cneaf/electricity/esr/esr_sum.html

The demand for power to serve retail open access declined in 2006 to 763 MW of coincident load in the Detroit Edison and Consumers service territories. By the end of 2006 the number of retail open access customers who chose alternative suppliers decreased to a total of 7,252 customers.¹⁴³

The actual 2006 peak demand for Consumers and Edison was 21,784 MW, which occurred on August 1, 2006. The only customer class that was interrupted during this period was the residential air conditioner users of Detroit Edison who were on the interruptible plan. During a normal summer of operations, Detroit Edison plans to cycle the interruptible air conditioner customers on six to ten days to relieve local circuit loadings.¹⁴⁴

In its 2007 summer assessment, MISO makes estimates about the range of expected demand and available generation and demand-reduction resources. It estimates that 130,000 MW of potential resources will be available. The average expected demand is 113,000 MW, which provides a reserve margin of 15%. The total generating and purchased power supply for Michigan this summer is 22,553 MW, versus the projected sum of the peak demands of 19,885 MW, giving a reserve margin of 13.4%. MISO's reserve margin is the same or higher than reserve margins for Detroit

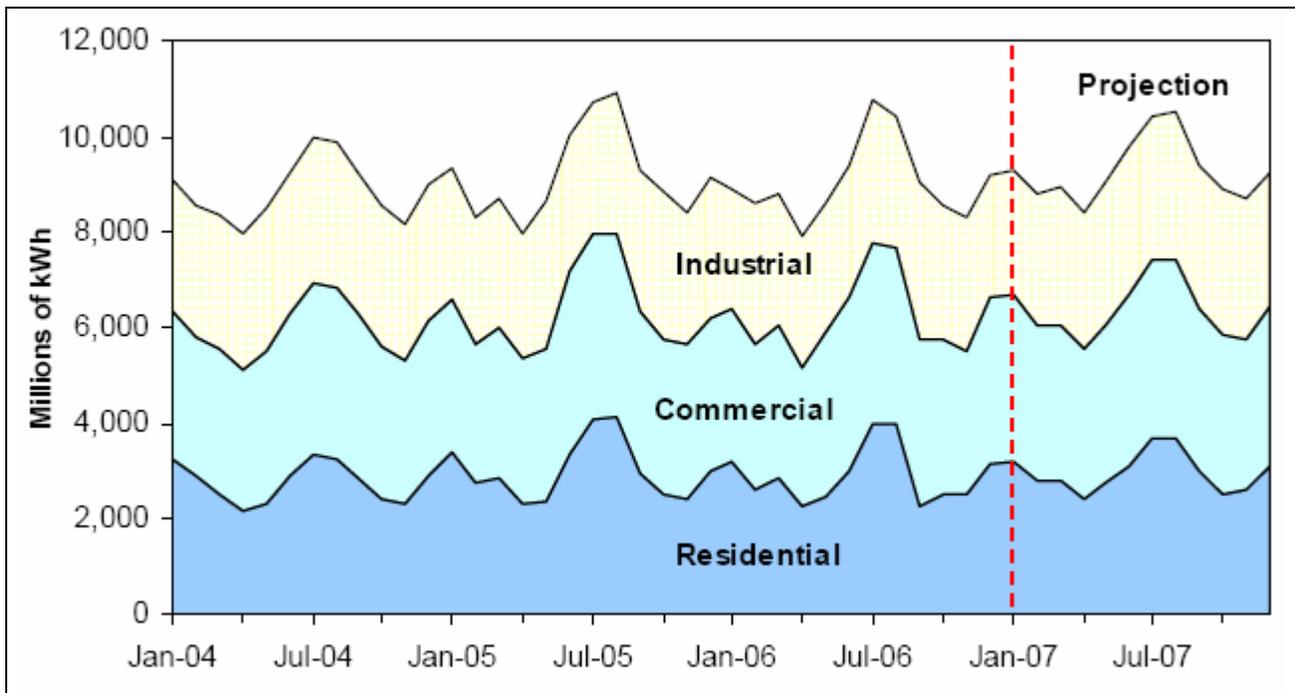
¹⁴³ Michigan Department of Labor & Economic Growth, Michigan Public Services Commission. (2007). *Michigan Energy Appraisal*. Lansing, MI: Author <http://www.dleg.state.mi.us/mpsc/reports/energy/07summer/ea-summer07.pdf>

¹⁴⁴ Ibid.

Edison and Consumers. This means that additional resources may be available to the utilities if demand in Michigan is higher than expected.¹⁴⁵

Excluding retail open access and interruptible loads for Detroit Edison and Consumers, the 2007 summer combined firm peak demand is projected to be 19,885 MW. This demand will be 655 MW above the utilities' in-state generating capacity of 19,230 MW. The utilities are purchasing power to assure adequate reserves.¹⁴⁶ Consumers intends to purchase 1,258 MW of seasonal capacity, which will result in an 11% reserve margin. Edison intends to purchase 2,065 MW to achieve a planning reserve of 15.2%.¹⁴⁷ Graph 4-1 and 4-2 describe projected electricity sales for summer 2007.

Graph 4-1 Schematic Projection of Electricity Sales in Michigan, Summer 2007



Source: Michigan Department of Labor & Economic Growth, Michigan Public Services Commission. (2007). *Michigan Energy Appraisal*

¹⁴⁵ Michigan Department of Labor & Economic Growth, Michigan Public Services Commission. (2007). *Michigan Energy Appraisal*. Lansing, MI: Author <http://www.dleg.state.mi.us/mpsc/reports/energy/07summer/ea-summer07.pdf>

¹⁴⁶ Ibid.

¹⁴⁷ Michigan Department of Labor & Economic Growth, Michigan Public Services Commission. (2007). *Michigan Energy Appraisal*. Lansing, MI: Author <http://www.dleg.state.mi.us/mpsc/reports/energy/07summer/ea-summer07.pdf>

Graph 4-2 Projection of Electricity Sales in Michigan, Summer 2007

Michigan Electricity Sales Projection (Millions of kWh)						
			Residential	Commercial	Industrial	Total
Historical	2004	Total	33,104	38,632	34,867	106,603
	2005	Total	36,141r	39,852r	34,399r	110,392
	2006	Total	34,740r	40,126r	33,765r	108,631
Projections	2007	January	3,235	3,302	2,617	9,154
		February	2,804	3,133	2,764	8,701
		March	2,804	3,164	2,914	8,884
		April	2,427	3,098	2,833	8,358
		May	2,756	3,276	3,007	9,039
		June	3,088	3,571	3,079	9,738
		July	3,694	3,693	3,009	10,396
		August	3,670	3,719	3,102	10,490
		September	2,988	3,373	3,034	9,395
		October	2,507	3,311	3,080	8,898
		November	2,584	3,155	2,928	8,668
		December	3,092	3,304	2,820	9,216
		2007	Total	35,653	40,099	34,046
2006-2007	Change		2.6%	-0.1%	0.8%	1.1%

NOTE: Projected electricity sales are based on historical trends.

SOURCES: Historical Data -- Energy Information Administration, U.S Department of Energy.

Projection -- Energy Data and Security, MPSC., r = revised

Source: Michigan Department of Labor & Economic Growth, Michigan Public Services Commission. (2007). *Michigan Energy Appraisal*

Residential customer usage drives peak summertime electricity demand in Michigan. Approximately 30% of load serving resources in Detroit Edison’s service territory went to residential consumers in 2006.¹⁴⁸ Of that the single largest contributor to summertime peak consumption is air conditioning. Air conditioning accounts for 50-60% of electrical demand in a typical residential home, and refrigeration (10-20% contribution) is a distant second. Clothes dryers, pool pumps/filters, water heaters, dehumidifiers, and a variety of other household appliances account for the rest. The residential customers contributed 4,708 MW (43.1%) to 2006 system peak demand. An Edison residential customer using 500 kWh per month currently pays about \$52.38 (10.48 cents per kWh using the April 2007 PSCR factor).¹⁴⁹

Some 63.7% of Detroit Edison’s load serving resources went to C&I customers in 2006.¹⁵⁰ Of that the single largest contributor to summertime peak consumption is also air conditioning. Commercial

¹⁴⁸ Source: Detroit Edison Load Research

¹⁴⁹ Michigan Department of Labor & Economic Growth, Michigan Public Services Commission. (2007). *Michigan Energy Appraisal*. Lansing, MI: Author <http://www.dleg.state.mi.us/mpsc/reports/energy/07summer/ea-summer07.pdf>

¹⁵⁰ The remaining 6.7% of Detroit Edison’s load serving resources go to street lights and wholesale. Source: Detroit Edison Load Research

and industrial customers respectively contributed 2,177 MW (19.9%) and 3,688 MW (33.7%) to 2006 system peak demand.¹⁵¹

Michigan and Detroit Edison lag behind respective peers in number and type of demand response options. In comparison to states of comparable size and electric demand, Michigan customers have a relatively small number of demand response options to choose from. As of this writing Detroit Edison is proactively formulating a DR/AMI strategy, and is working in conjunction with the Michigan Public Services Commission and other LSEs to craft robust demand response strategy beneficial to the company and its customers.

III. Stakeholder Interests and Preferences

Aligning Incentives

Customer satisfaction and preferences as related to demand response in southeast Michigan may be evaluated by analyzing survey results (administered to both participating and non-participating retail customers).¹⁵² Resolving competing interests among customer classes, and between customers and utilities, is a challenge inherent in the development of a demand response program.

Generally the lack of utility incentives to the promotion of demand response has been a long-standing problem. As private enterprises, investor-owned utilities have an incentive to sell as much electricity as possible, even when additional usage is wasteful (from a market efficiency standpoint). Likewise utilities lose revenue from reductions in demand, even when the reduced sales promote market efficiency. Because most utility rates are based on a combination of kWh and peak kW demand charges, demand reductions associated with incentive-based demand response negatively impact utility revenues. Even when reductions are short-lived, the potential for a reduction in revenues discourages demand response. The disincentive is greater for utilities in restructured states with active ISO demand response programs. Consequently electric utilities have been either reluctant to promote these programs or request some form of lost-revenue recovery. While various solutions continue to be attempted, with varying levels of success, this issue has proven to be difficult to address.¹⁵³

Policies to address utility disincentives to providing demand response programs have been suggested and implemented for some time.¹⁵⁴ Proposed policy innovations fall into three categories:

¹⁵¹ Source: Detroit Edison Load Research

¹⁵² In preparing its 2004 Demand Response Program Evaluation, ISO New England Inc. (ISO-NE) evaluated customer satisfaction and preferences by analyzing the results of a survey that was administered to both participating and non-participating retail customers. All current program participants received the survey. In addition, customer contact lists were developed to provide a frame for surveying customers that previously participated, but retired from the program, as well as customers that had shown interest and had been exposed to the program particulars, but chose not to participate. The survey responses provided data for the variety of analyses undertaken to characterize and compare the perceptions of the customer groups. (See ISO-NE 2004 Demand Response Program Evaluation, page 1-2 http://www.iso-ne.com/genrtion_resrcs/dr/rpts/2004_annual_evaluation_filing.pdf)

¹⁵³ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 72). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

¹⁵⁴ Ibid., pp. 127

(1) Removing Disincentives – policy innovations that seek to remove retail rate structures and designs that discourage implementation of demand response by decoupling profits from sales volumes.

(2) Recovering Costs - policy innovations that give utilities the opportunity to recover the costs of implementing demand response programs.

(3) Rewarding Performance – policy innovations that reward utilities for implementing high-performance demand response programs. These can take the form of payments based on increased customer enrollment in demand response programs, or retail rates and regulatory policies that allow for higher returns on investment (if demand response programs demonstrate success in reducing peak demand or peak period energy use). Shared-savings mechanisms (where utilities share the savings and/or profits associated with the demand-response programs with customers or third-party aggregators) can also be employed as another performance incentive. These policy innovations are also known as “performance-based ratemaking.”

Decoupling policies are being actively examined in state proceedings, and have been implemented in California and Oregon. Other states such as New York and Connecticut rejected rate decoupling, noting the negative impact that large revenue accruals can have on rate stability. Discussions on the best means to address utility disincentives continue.¹⁵⁵

Differing Abilities to Respond, Targeted Programs

The different needs and knowledge levels of *how* to respond, as well as varying *abilities* to respond, should be considered when developing Detroit Edison’s portfolio of demand response mechanisms. Customers will need targeted and ongoing training and education, as well as targeted incentives. For instance, customer price-responsiveness varies significantly by market segment among commercial and industrial users. Recognizing this fact, regulators and other stakeholders have begun moving towards creating targeted demand response programs. At a CAISO forum held in early 2007 participants concluded that demand response programs should be different for different customer classes.¹⁵⁶ Table 4-1 demonstrates how one state, California, approached the creation of demand response programs that target specific customer segments.

¹⁵⁵ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 127). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

¹⁵⁶ Edison Electric Institute. (July 2007). *Demand Response Review*. Washington, DC: Author, pp. 2

Table 4–1 CEC Vision for Creating Targeted, Segment-Specific, Demand Response Programs

Customer Class	Default Rate Structure	Rate Structure Options
Residential	CPP	TOU or Flat with hedge
Small Commercial 20-200 kW	CPP	TOU or Flat with hedge
Medium Customers 201-999 kW	CPP	TOU or RTP (two part)
Large Customers	RTP (two part)	TOU or CPP

Source: California Energy Commission (CEC)

Current Customer Experience with Demand Response

A recent report¹⁵⁷ concludes that over the past year there has been a significant level of demand response activity for residential customers. Nearly two-thirds of the responding utilities cited air conditioning switching programs, and nearly one half mentioning water heating controls, as the leading demand response options for residential customers. Programmable thermostats and load curtailment programs were less used with residential customers. AMI programs were underway or planned in about one quarter of reporting utilities.

The same report concluded that smaller commercial customers have not been heavily involved in load control programs, but 23% were involved with either current or planned AMI projects. Larger commercial customers were very likely to be involved in load curtailment programs with their utilities, but not heavily engaged in programs for air conditioning or water heating controls.¹⁵⁸

Lastly industrial customers were reported to be very likely (83%) to be involved in load response and curtailment (passive demand response) programs, but not likely to be involved in “residential” type (e.g. in AC and WH interruption programs) load control activities.¹⁵⁹

A 2007 demand response market potential simulation of large C&I customers conducted by researchers at the Lawrence Berkeley National Laboratory (LBNL) examined demand response participation rates among customers in five segments.¹⁶⁰ Table 4-2 describes the demand response options included in the simulation.

¹⁵⁷ Newton-Evans Research Company. (2007). *Demand Response/Load Management Programs Outlook: 2007*.

Retrieved July 2007 from <http://www.energybusinessreports.com/shop/item.asp?itemid=1248>

¹⁵⁸ Ibid., pp. 7

¹⁵⁹ Newton-Evans Research Company. (2007). *Demand Response/Load Management Programs Outlook: 2007*.

Retrieved July 2007 from <http://www.energybusinessreports.com/shop/item.asp?itemid=1248>

¹⁶⁰ The five customer segments were manufacturing (SIC 01–39), government/education (SIC 81–98), commercial/retail (SIC 50–79), healthcare (SIC 80), and public works (SIC 40–49).

Table 4-2 Demand Response Options Included in the Simulation

DR Option	Description
Optional hourly pricing	<ul style="list-style-type: none"> • A dynamic pricing tariff with bundled charges for delivery and commodity • Usually offered by vertically integrated utilities on an optional basis • Typical rate design is a two-part structure, in which a customer baseline load (CBL) is established and billed at an otherwise-applicable tariff rate, with deviations in actual usage billed at hourly prices
Default hourly pricing	<ul style="list-style-type: none"> • A dynamic pricing tariff in which distribution charges are unbundled from commodity charges • Usually offered by distribution utilities or default service providers in states with retail electric competition • Typical rate design includes demand and/or volumetric distribution charges, with all commodity usage billed at an hourly rate, often indexed to a day-ahead wholesale market
Short-notice emergency program	<ul style="list-style-type: none"> • A program that offers customers financial incentives for curtailing load when called by a program operator on short notice (i.e., 1-2 hours) in response to system emergencies • Typically, customer response is voluntary (i.e., in some programs, no penalties are levied for not curtailing when called)
Price-response event program	<ul style="list-style-type: none"> • A program that pays customers for measured load reductions when day-ahead wholesale market prices exceed a floor • Some programs may include bid requirements (i.e., customers are only paid for curtailments that they specify in advance) and/or penalties for failing to respond when committed
Critical-peak pricing	<ul style="list-style-type: none"> • A dynamic-pricing tariff similar to a time-of-use rate most of the time, with the exception that on declared “critical-peak” days, a pre-specified higher price comes into effect for a specific time period

Source: “Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study,” pg 28

Table 4-3 highlights the demonstrated participation rates when customers were offered the demand response options described previously in Table 4-2.

Table 4-3 Participation Rates in Demand Response Programs and Dynamic Pricing Tariffs

DR Option	Business Type	Customer Size (peak demand)			
		0.35–0.5 MW	0.5–1 MW	1–2 MW	>2 MW
Optional hourly pricing	Commercial/retail	0%	0%	1%	2%
	Government/education	3%	4%	6%	25%
	Healthcare	0%	0%	1%	2%
	Manufacturing	3%	5%	6%	25%
	Public works	0%	0%	3%	20%
Default hourly pricing	Commercial/retail	4.30%	11%	50%	43%
	Government/education	4.20%	10%	30%	42%
	Healthcare	0.70%	1.80%	50%	7.10%
	Manufacturing	3.30%	8.30%	29%	33%
	Public works	3.70%	9.20%	50%	37%
Short-notice emergency program	Commercial/retail	1.20%	23%	5.50%	20%
	Government/education	0.30%	5.30%	2.60%	9%
	Healthcare	0.60%	4.20%	4.30%	22%
	Manufacturing	0.20%	15%	17%	23%
	Public works	1.10%	10%	67%	17%
Price-response event program	Commercial/retail	0.30%	0.80%	1.80%	5.70%
	Government/education	0.30%	2.90%	4.10%	10%
	Healthcare	0.30%	1.60%	8.90%	22%
	Manufacturing	5.70%	10%	9.10%	30%
	Public works	0.10%	0.20%	0.40%	1.10%
Critical-peak pricing	Commercial/retail	0.90%	3.10%	5.20%	4.20%
	Government/education	1.50%	4.10%	2.30%	1.90%
	Healthcare	0.90%	3.10%	5.20%	4.20%
	Manufacturing	0.90%	4.50%	7.30%	6.90%
	Public works	1.20%	3.30%	1.30%	2.80%

Source: “Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study,” pg 31

Note: *Red-italicized* figures are based on expert judgment.

LBNL researchers used a combination of the “translated experience” and “expert judgment” approaches¹⁶¹ to determine participation rates. Where possible, LBNL researchers used actual program participation data from the data sources. See Appendix H for sources of data used in this market potential simulation.

The highest participation rates are observed for large customers (>1 MW) in the default hourly pricing tariff. LBNL researchers believe this is largely explained by the default nature of the tariff. Another factor that strongly impacts participation rates is the definition and size of the eligible customer population. For the default hourly pricing tariff, only a specific set of large customers, with peak demand above 2 MW were eligible. In contrast, the other programs were open to significantly wider classes of customers.¹⁶²

Researchers believe that a number of other factors may also influence rates of customer participation in demand response programs and tariffs. Most obviously, program design features, including the structure and level of incentive payments, penalties for non-performance, and the duration, frequency and advance notice of events, may affect customer decisions to enroll.¹⁶³

Other program-specific factors may include customer familiarity with and/or the reputation of the entity administering the program, the effectiveness of marketing and/or customer education efforts, and the availability of technical or financial assistance.¹⁶⁴

Given the small size of the sample researched (six programs) it is difficult to draw conclusions about which program designs encourage or discourage participation. Nonetheless, evaluations of some of these programs did examine drivers for participation, with statistically robust results.¹⁶⁵

It is important to note that, for the purposes of this study, demand response options were analyzed independently. That is, researchers did not account for possible interactions between different options, should they be offered simultaneously to a given set of customers. Results therefore likely overestimate the combined market potential for these demand response programs and dynamic pricing tariffs should two or more of them be offered to the same customers at once. Program designers that intend to offer a variety of demand response options should ensure that such interactions are accounted for in market potential studies.¹⁶⁶

¹⁶¹ “Translated Experience” refers to the use of actual participation rates for demand response programs implemented for similar market segments or target populations, and/or in markets with similar supply conditions and market structures. “Expert judgment” refers to estimates solicited from a panel of individuals with experience or insight.

¹⁶² Goldman, C., Hopper, N., & Bharvirkar, R. (January 2007) *Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers: A Scoping Study*. (pp. 30). Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory

<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

¹⁶³ Ibid., pp. 31

¹⁶⁴ Goldman, C., Hopper, N., & Bharvirkar, R. (January 2007) *Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers: A Scoping Study*. (pp. 32). Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory

<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

¹⁶⁵ Ibid.

¹⁶⁶ Goldman, C., Hopper, N., & Bharvirkar, R. (January 2007) *Estimating Demand Response Market Potential Among Large Commercial and Industrial Customers: A Scoping Study*. (pp. 27). Berkeley, CA: Ernest Orlando Lawrence Berkeley National Laboratory

<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

Lastly it should be noted that some utility executives have expressed concerns that price signals are rarely high enough to get customers to curtail. Some observe that, excluding large C&I customers with distributed generation facilities, quoted prices would have to be many times the current peak average (and probably past a legal amount) in order to achieve significant curtailment.

IV. Customer Responsiveness: Potential Barriers and Mitigations

National researchers consistently assert that *most customers (particularly residential) resist demand response programs that require effort*, and as such the basic design of a demand response program should be simple. Customers tend not to pay much attention to energy bills unless they are extremely high. In addition most customers will not engage in tracking electricity usage/prices on a daily basis. The “full cost” of responding to price changes is much more than the price difference. Customers must act in order to respond and these actions require time and effort. Lowering the incremental “cost” of responding should increase the amount of price response.

Past experience in Michigan suggests that residential customers will accept up to 10 load control requests per year. More than this is likely to cause a negative backlash. However, customers may be willing to accept more than ten load control requests if they are compensated with rebates each time a request is made. Additionally, demand response programs that are targeted to large commercial and industrial (C&I) customers must satisfy their respective business operational needs.

Researchers suggest that in order for a demand response program to be effective, customers should be educated about the fluctuating real price of electricity. The features of the demand response program must also be presented in ways that are easy to understand. *Technology products that enable and automate demand response must be included in any program, and the costs of these are often subsidized by LSEs.*

Fully Automated Demand Response

Research into the feasibility and nature of *fully automated* demand response strategies (in large facilities) is being conducted by the Lawrence Berkeley National Laboratory (LBNL).¹⁶⁷ This is part of a broader effort to improve customer acceptance rates for demand response.

There are three levels of demand response automation. *Manual demand response* refers to the manual turning off of lights or equipment. This approach to demand response can be labor-intensive. *Semi-automated demand response* involves the use of energy management control systems for load shedding, where a preprogrammed load shedding strategy is initiated by building facilities staff. *Fully-Automated Demand Response* (Auto-DR) is initiated at a building or facility through receipt of an external communications signal. A pre-programmed load shedding strategy is automatically initiated by the system without the need for human intervention. An important component of Auto-DR is that facility managers are able to “opt out” or “override” an individual

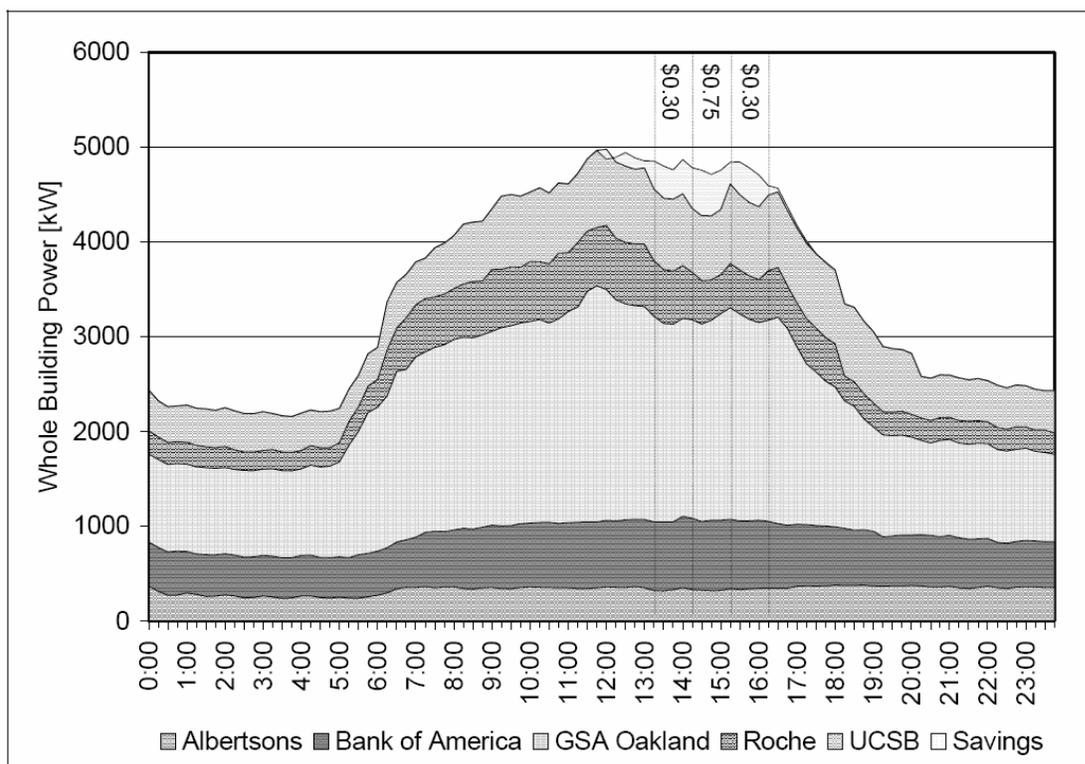
¹⁶⁷ A 2003 research paper on Auto-DR focused on technology development, testing, characterization, and evaluation. The research included the related decision-making perspectives of the facility owners and managers. Researchers also sought to develop and test a real-time signal for automated demand response that might provide a common communication infrastructure for diverse facilities.

demand response event if it occurs at a time when the reduction in end-use services is not desirable.¹⁶⁸

LBNL researchers conducted tests on five buildings simultaneously over a two-week test period. The shed strategies consisted of the following type of control changes: zone set-point change, direct control of fans, resetting duct static pressure, resetting of cooling valves, reduction of overhead lighting, and reduction of anti-sweat heaters.¹⁶⁹

The aggregated total demand for the five facilities was nearly 5,000 kW. The maximum peak savings was about 10% of that load, or about 500 kW. The maximum load reduction at each site ranged from 8 kW (Bank of America) to 240 kW (GSA). The maximum savings occurred during the high-price time for three of the five sites. There were no tenant (or other) complaints at any of the sites. Graph 4-2 depicts Auto-DR electric load shed from the five sites on Wed. Nov. 19, 2003.¹⁷⁰

Graph 4-3 Auto-DR Electric Load Shed from Five Sites on Wed. Nov. 19, 2003



Source: “DEVELOPMENT AND EVALUATION OF FULLY AUTOMATED DEMAND RESPONSE IN LARGE FACILITIES,” page E-3

¹⁶⁸ Piette, M. A., Sezgen, O., Watson, D., & Motegi, N. (2005). *Development and Evaluation of Fully Automated Demand Response in Large Facilities*. (CEC-500-2005-013). Berkeley, CA: PIER Demand Response Research Center <http://drcc.lbl.gov/drcc-pubs-auto-dr.html>

¹⁶⁹ Piette, M. A., Sezgen, O., Watson, D., & Motegi, N. (2005). *Development and Evaluation of Fully Automated Demand Response in Large Facilities*. (CEC-500-2005-013, pp. E-4). Berkeley, CA: PIER Demand Response Research Center <http://drcc.lbl.gov/drcc-pubs-auto-dr.html>

¹⁷⁰ Ibid.

Important implications identified by LBNL researchers include:¹⁷¹

1. Fully automated demand response is technically feasible with minor enhancements to current state-of-the-art technology.
2. New Internet technology enhances the capabilities of existing building systems to enable demand response.
3. Automation enhances demand response programs.
4. Many energy managers at large facilities support the objectives of demand response and believe that DR programs and tariffs will increase in their importance and prominence. They also believe that new technologies will assist them in participating in these programs.
5. New knowledge is needed to procure and operate technology and strategies for demand response.

V. Recent Performance of Demand Response

A Lawrence Berkeley National Laboratory (LBNL) survey of ISOs and utilities that looked at the performance of demand response programs during the summer of 2006, revealed that following about effective demand response programs:

1. Reliability-based Demand Response programs are performing well

Demand response resources, such as direct load control (DLC), large customer emergency and capacity programs, and interruptible/curtailable (I/C) rates, performed as (or better than) expected, with load response in some places as high as 80% or more of enrolled resources.¹⁷²

Most of the individuals interviewed by LBNL staffers shared the view that reliability-based demand response had matured in the last five years and was increasingly recognized as a viable resource by multiple parties (including grid operators). For staffers at utilities that engage in integrated resource planning (IRP), demand response was being viewed through this lens. The concept of demand response as a viable resource is manifested through efforts to facilitate participation by customer loads in wholesale markets for capacity, reserves, and energy, in regions with organized wholesale markets.¹⁷³

2. “Handholding” is essential to high responsiveness to some Demand Response programs

Several utilities and third-party aggregators attributed the healthy response of reliability programs to a large degree of proactive customer engagement (what respondents called “handholding”) with large C&I customers, noting the high cost of maintaining customer relationships. A number of

¹⁷¹ Piette, M. A., Sezgen, O., Watson, D., & Motegi, N. (2005). *Development and Evaluation of Fully Automated Demand Response in Large Facilities*. (CEC-500-2005-013, pp. E-4). Berkeley, CA: PIER Demand Response Research Center <http://drcc.lbl.gov/drcc-pubs-auto-dr.html>

¹⁷² Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author <http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

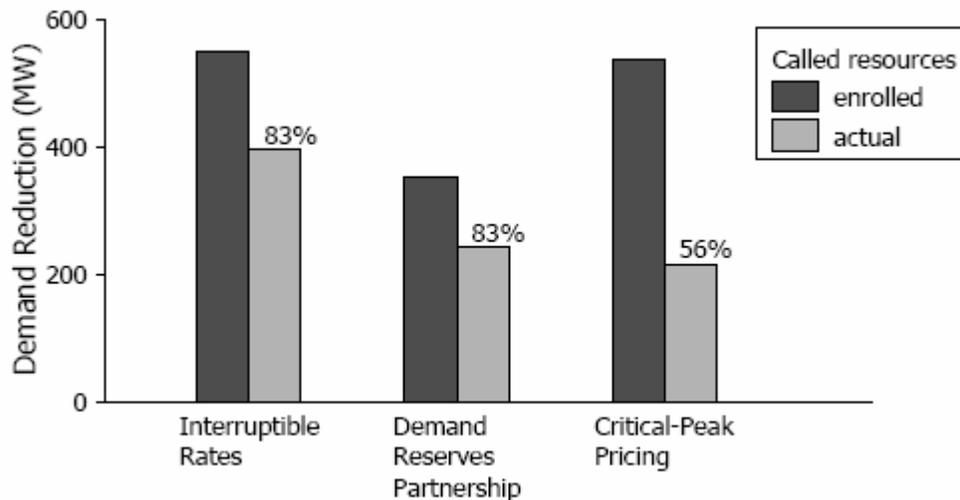
¹⁷³ Ibid.

respondents described multiple ways of getting the message across to their large customers when events were called. In addition to the standard event notifications, utilities and third-party aggregators telephoned individual customers to remind them of events. In some cases, they were able to identify customers that weren't responding as expected and call them to address the problem; this was made possible by near-real-time information systems that provided quick feedback on customer response.¹⁷⁴

3. Threat of penalties boosts responsiveness

There appears to be a positive correlation between load curtailment and penalties for non-compliance. Demand response programs run by California's three investor-owned utilities (IOUs) demonstrate this point. For both interruptible rates and the Demand Reserves Partnership, programs that impose significant penalties for not responding when called, the actual response was 83% of enrolled resources. Resources on the large customer critical-peak pricing (CPP) rate which can be triggered by either economic or reliability criteria, and does not have strict penalties, were somewhat less responsive. Actual load curtailments were 56% of the subscribed load on July 24, 2006.¹⁷⁵ Graph 4-4 highlights the performance of large customer demand response programs run by California's IOUs.

Chart 4-4 Performance of California's IOUs Large Customer Demand Response Programs, Summer 2006



Sources: PG&E (2006), SCE (2006), SDG&E (2006)

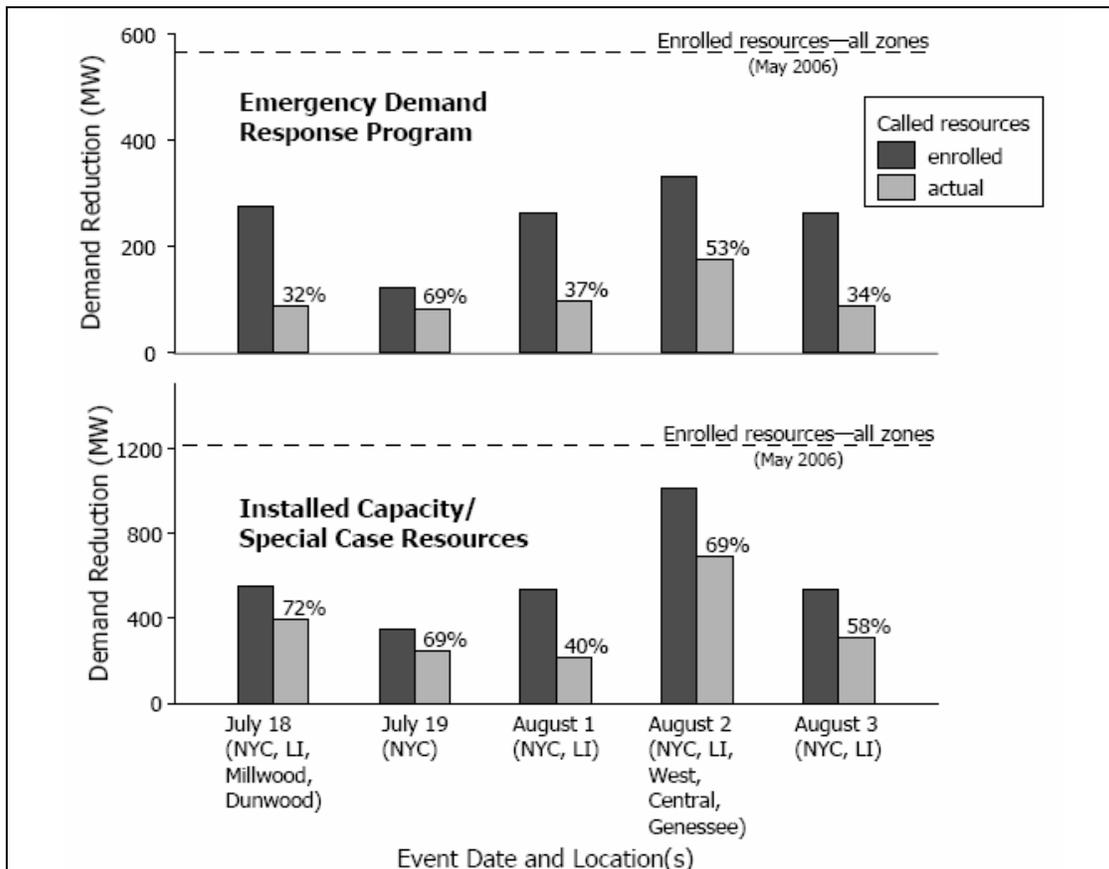
NYISO's two emergency programs, the Emergency Demand Response Program (EDRP) and the Installed Capacity/Special Case Resources (ICAP/SCR), provide an example of targeted, locational dispatch of DR resources. In each event, only a subset of the NYISO load-zones' demand response resources were dispatched. On average, about half of the total enrolled load in the ISO control area for each program was dispatched. The programs were called most frequently in New York City and Long Island, the areas facing most of the transmission constraints in the state, with more widespread events occurring on July 18 and August 2, 2006.

¹⁷⁴ Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author
<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

¹⁷⁵ Ibid.

The performance of these resources varied, but the percent of enrolled load that responded was consistently higher in the ICAP/SCR program (which offers reservation payments and levies penalties for non-performance) than for EDRP (a voluntary program that compensates customers for load reductions only during events). On average, actual load reductions were 62% of called resources for ICAP/SCR and 43% for EDRP.¹⁷⁶ Graph 4-5 highlights the performance of both the EDRP and ICAP/SCR during the summer of 2006.

Graph 4-5 Performance of NYISO’s EDRP and ICAP/SCR, Summer of 2006



Sources: NYISO (2007)

4. Economic Demand Response demonstrates mixed results

The performance of economic demand response programs and dynamic pricing tariffs received less glowing reports in interviews conducted by LBNL researchers. Because wholesale market prices were not very high or spiky during summer 2006, economic demand response programs either were not called or did not garner much customer response in some areas of the country. While dynamic pricing tariffs, such as RTP and CPP, are offered by at least 50 utilities nationally, most of those interviewed had little information on their performance in 2006, and information on load impacts was not available.¹⁷⁷

¹⁷⁶ Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author <http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

¹⁷⁷ Ibid.

In spite of their lackluster performance a small number of economic demand response programs did generate considerable activity in 2006. Cumulative energy reductions throughout this period ranged from a few thousand to almost 80 thousand MWh. Most of the energy reductions for the PJM and ISO-NE programs (over 80%) occurred between May and August. In contrast, only 7% of the load reductions in the NYISO day-ahead market demand response program occurred during this time period, demonstrating the potential for economically-driven demand response to provide load curtailments year-round.¹⁷⁸

The maximum capacity impacts calculated for economic demand response programs during summer 2006 were significant (~50–450 MW) and mostly occurred on days when system emergency events were declared or system demand was high. Average energy payments for curtailed load ranged from roughly \$100 to \$175 per MWh for the ISO/RTO market based programs, while the customer incentive for the California Demand Bidding program was fixed at \$350/MWh.¹⁷⁹

5. Growing focus on resolving M&V issues

A number of utility representatives indicated to LBNL researchers that they did not yet regard economic demand programs (e.g., demand bidding) or dynamic pricing (e.g., RTP, CPP) as “firm” resources based on their experience to date. Some described these options as primarily improving the overall efficiency of electricity markets, rather than providing a specific demand response resource. Others were simply more comfortable with their ability to count on reliability options to provide load reductions that could compete with (and supplant) supply-side peaking resources. This was particularly the case for more traditional programs such as I/C rates and DLC programs.¹⁸⁰ This ambivalence will continue until a standard for measuring and validating demand response provided by economic demand response and dynamic pricing programs is established.

6. Small-to-medium sized commercial and institutional customers are up-and-coming market

Third-party aggregators are emerging as a viable business model in selected markets. These companies aggregate customer loads to participate in both ISO and utility demand response programs across the country. Most of their activity, however, is in programs where capacity payments or energy incentives are high relative to the rest of the country.¹⁸¹

LBNL researchers expect to see continued growth in the role of third parties in aggregating load for demand response, particularly if forward capacity markets develop and expand. All three aggregators interviewed (as well as other respondents) identified small-to-medium sized commercial and institutional customers as a source of large untapped potential and the next up-and-coming market for demand response load aggregation.¹⁸²

7. Growing interest in fully automated demand response

¹⁷⁸ Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author
<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

¹⁷⁹ Ibid.

¹⁸⁰ Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author
<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

¹⁸¹ Ibid.

¹⁸² Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author
<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

LBNL researchers found that more widespread dissemination of the concept of fully automated demand response (Auto-DR) can play an important role in supporting the activities listed above. Many believe that Auto-DR can play an important role in improving the reliability and sustainability of demand response while minimizing the impact on customer comfort, convenience and productivity.¹⁸³

VI. Summary

Most electricity customers, particularly residential, resist demand response programs that require effort, and as such the basic design of a demand response program should be simple. Technology products that enable and automate demand response must be included in any program, and the costs of these are often subsidized by LSEs.

¹⁸³ Ernest Orlando Lawrence Berkeley National Laboratory, Energy Analysis Department. (May 2007). *The Summer of 2006: A Milestone in the Ongoing Maturation of Demand Response*. Berkeley, CA: Author
<http://eetd.lbl.gov/ea/EMP/drlm-pubs.html>

SECTION 5: DEMAND RESPONSE PILOT PROGRAM RECOMMENDATIONS

The Michigan Public Services Commission (MPSC) issued an order¹⁸⁴ on June 12, 2007 initiating a collaborative process among the state's LSEs to investigate the feasibility and potential benefit of widespread demand response measures that utilize advanced metering technology. These pilot programs will assess quantitative impacts, technical feasibility, and operational aspects of demand response measures, providing both data and practical experience. Should these pilot programs demonstrate the cost effectiveness of demand response programs the MPSC may seek the authority to require utilities to offer demand response programs to their customers.¹⁸⁵

Nationwide the primary objectives of a demand response pilot program have included:

1. Estimating the average impact of time-varying rates and AMI on energy use and develop models that can be used to predict impacts under alternative pricing plans.
2. Determine customer preferences and market shares for time-varying rate options.
3. Evaluate the effectiveness of, and customer perceptions about, pilot features and educational materials.
4. Determine demand response program structure that meets a utility's operational needs.
5. Determine demand response program structure that brings value to customers and a high-level of satisfaction.
6. Determine demand response program structure that offers annual savings that are at or below the cost of new generation (i.e. demand response should offset peaker generation).

A preliminary understanding of consumption patterns and past customer responsiveness (as described in SECTION 4 of this report) is crucial to the design and execution of any demand response pilot. Following Demand Response Market Potential (DRMP) methodologies (as described in SECTION 2 of this report) it is suggested that four rate schemes: CPP, RTP, TOU, and Interruptible/Curtailable. In addition, a smaller prepaid energy program may be considered in a Michigan demand response pilot.

I. Critical Peak Pricing (CPP) Pilot

Of all time-varying rates used for demand response, CPP has been shown to have the greatest impact on load shedding during many pilot programs.

¹⁸⁴ See MPSC press release "MPSC Starts Collaborative Proceeding for Demand Response Pilot Program" at <http://www.michigan.gov/mpsc/0,1607,7-159-16377-170116--,00.html>, and text of the actual order at http://www.cis.state.mi.us/mpsc/orders/electric/2007/u-15277_06-12-2007.pdf

¹⁸⁵ Michigan Public Service Commission. (2007). *MICHIGAN'S 21ST CENTURY ELECTRIC ENERGY PLAN*. (pp. 7). Lansing, MI: Author
<http://www.cis.state.mi.us/mpsc/electric/capacity/energyplan/index.htm>

California SPP

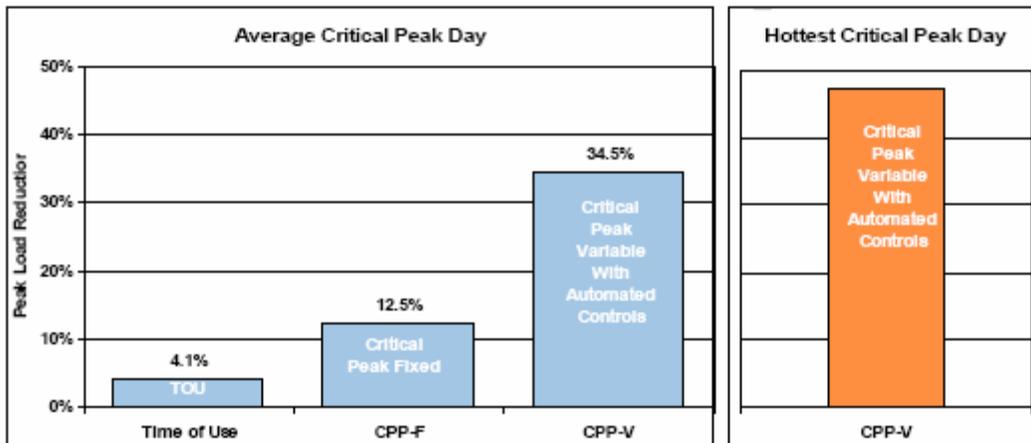
California's Statewide Pricing Pilot (SPP) ran from July 2003 to December 2004. The program involved the state's three investor-owned utilities (IOUs) and was implemented through a joint effort of the California Public Utilities Commission (CPUC), the California Energy Commission (CEC), and the California Power Authority (CPA). Some 2,500 customer participated in the pilot.

Three rate structures were tested as part of the SPP¹⁸⁶:

1. A TOU rate with a peak price that was 70% higher than the standard rate and twice as high as the off-peak price.
2. Two CPP rates: a statewide TOU rate layered with a CPP that could be dispatched with day-ahead notice up to 15 times annually (CPP-F), and a variable critical-peak rate (CPP-V), targeted at a population that had already participated in a smart thermostat pilot. CPP-V was dispatched with four-hour day-of notification, for two-to-five hours. The CPP-V customers had the option of free enabling technology to facilitate their responses.

SPP reductions in peak-period energy use ranged from a low of 8.1%¹⁸⁷ to a high of 27.2%¹⁸⁸ for residential customers. Reductions among C&I customers ranged from a low of 6.1%¹⁸⁹ to a high of 14.3%.¹⁹⁰ Graph 5-1 highlights how customer peak reduction differed by type of rate offering.

Graph 5-1 Customer Response to California Pilot CPP rate offerings



Source: Roger Levy, Joint California Workshop, "Advanced Metering Results and Issues" September 2004.

¹⁸⁶ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 58). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

¹⁸⁷ Average summer reduction in peak-period energy use for residential customers on CPP-F rates during the outer summer (the milder months of May, June and October) period.

¹⁸⁸ Average summer reduction in peak-period energy use for Track C residential customers (customers with central AC, and AMI meter, and a smart thermostats) on a CPP-V rate. Roughly two-thirds of the Track C reductions can be attributed to the smart thermostat technology, the remainder to behavioral changes.

¹⁸⁹ Average summer reduction in peak-period energy demand for C&I customers on a CPP-V rate during the summer period.

¹⁹⁰ Average summer reduction in peak-period energy demand for C&I customers on a CPP-V rate with pre-existing AMI installation.

Tables 5-1 and 5-2 summarize the average peak-period impacts by rate tested, for residential and C&I customers respectively.

Table 5-1 SPP Average Peak-Period Impacts for Residential Customers

Treatment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track A CPP-F	Critical Weekday	P = 59 OP = 9 D = 23 C = 13	-13.1% average summer -14.4% inner summer -8.1% outer summer	No statistically significant difference for inner summer between 2003 and 2004 (differences across the two years can not be estimated for the outer summer Track A or the average summer).
	Normal Weekday	P = 22 OP = 9 D = 12 C = 13	-4.7% average summer -5.5% inner summer -2.3% outer summer	Difference between critical & normal days is primarily due to price differences and secondarily to differences in weather.
Track A TOU	All Weekdays	P = 22 OP = 10 D = 13 C = 13	-5.9% inner summer 2003 -0.6% inner summer 2004 -4.2% outer summer 2003/04	Results are suspect because of the small sample size and observed variation in underlying model coefficients across the two summers. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A CPP-V	Critical Weekday	P = 65 OP = 10 D = 23 C = 14	-15.8% avg summer 2004 Represents average across households with and without enabling technologies - could not separate price and technology impacts	Not directly comparable to CPP-F results due to differences in population (CAC saturation for CPP-V treatment group twice that of CPP-F; CPP-V average income much higher; 2/3 of CPP-V customers had enabling tech.; all households located in SDG&E service territory).
	Normal Weekday	P = 24 OP = 10 D = 14 C = 14	-6.7% average summer 2004	See above comments about population differences
Track C CPP-V	Critical Weekday	Same as for Track A	-27.2% combined tech and price impacts for average summer 2003/04 -16.9% impact for tech only -11.9% incremental impact of price over and above tech impact	Not directly comparable to Track A results due to population differences (All Track C customers are single family households with CAC located in SDG&E service territory). Some evidence that impacts fell between 2003 & 2004
	Normal Weekday	Same as for Track A	-4.5% average summer 2003/04	See above comments about population differences
Track A Info Only	Critical Weekday	13 for all periods	Statistically significant response in one of two climate zones in 2003. No response in 2004	Analysis provides no evidence of sustainable response in the absence of price signals.

P = peak period price; OP = off-peak price; D = daily price; C = control group price

Source: Charles River Associates, "IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT" March 2005

Table 5-2 SPP Average Peak-Period Impacts for C&I Customers

Treatment	Day Type	Avg. Price (¢/kWh)	Impacts	Comments
Track A TOU LT20	All Weekdays	P = 28 OP = 12 D = 18 C = 18	-0.3% in 2003 -6.8% in 2004	The 2003 value is not statistically significant. Small sample size and variation in underlying model coefficients across summers suggest estimates may be suspect. Recommend using normal weekday CPP-F model to predict for TOU rate.
Track A TOU GT20	All Weekdays	P = 23 OP = 12 D = 16 C = 15	-3.9% in 2003 -8.6% in 2004	The difference between 2003 and 2004 is statistically significant. Same caveat as described above for LT20 customers.
Track A CPP-V LT20	Critical Weekday	P = 81 OP = 12 D = 30 C = 17	-6.1% in 2004	This treatment was not implemented in 2003. Price responsiveness measure is Track A small but statistically significant
	Normal Weekday	P = 20 OP = 12 D = 15 C = 17	-1.5% in 2004	Same comments as above
Track A CPP-V GT20	Critical Weekday	P = 66 OP = 11 D = 24 C = 15	-9.1% in 2004	This treatment was not implemented in 2003 This segment is more price Track A responsive than LT20 customers
	Normal Weekday	P = 18 OP = 12 D = 14 C = 15	-2.4% in 2004	Same comments as above
Track C CPP-V LT20	Critical Weekday	P = 87 OP = 12 D = 33 C = 18	-14.3% combined tech and price impact for average summer 2003/04 -18.2% for tech alone +4.5% incremental impact of price over and above tech impact	The tech only impact is higher than the combined price/tech impact, indicating that price does not provide any incremental impact for this Track C customer segment
	Normal Weekday	P = 21 OP = 12 D = 16 C = 18	+1.1 in average summer 2003/04	The estimate is not statistically significant. Additional evidence that this customer segment is not price responsive.
Track C CPP-V GT20	Critical Weekday	P = 71 OP = 11 D = 24 C = 15	-13.8% combined tech & price impact for average summer 2003/04 -11.0% for tech alone -3.2% incremental impact of price over & above tech impact	Incremental impact of price over technology declined by roughly 75% between 2003 and 2004 GT20 participants use significantly less electricity on average than the Track C average control group
	Normal Weekday	P = 19 OP = 11 D = 14 C = 15	-0.9% in average summer 2003/04	Same comments as above

P = peak period price; OP = off-peak price; D = daily price; C = control group price
 Source: Charles River Associates, "IMPACT EVALUATION OF THE CALIFORNIA STATEWIDE PRICING PILOT" March 2005

Key SPP findings related to potential CPP effectiveness (for residential customers) include:

- Peak-period impacts did not drop on the second or third days of multi-day critical events (such as might occur during a heat wave).
- There was no change in total energy use across the entire year based on average SPP prices.
- Appealing for load reductions on critical days in the absence of price incentives did not result in sustainable demand response.
- Responsiveness varied with customer characteristics. Central Air Conditioning (CAC) saturation, income and college education significantly influence demand response.

Gulf Power's GoodCents SELECT

The Pensacola, Florida based Gulf Power Company employs a very successful CPP demand response program. GoodCents® SELECT is a residential advanced energy management system that gives customers control over their energy purchases by allowing them to program their central heating and cooling system, electric water heater and their pool pump to automatically respond to varying prices.

Gulf Power began marketing GoodCents® SELECT to residential customers in 2000. By 2003 the program had 6,000 participants.¹⁹¹ This program is similar to the Intelligent Link Program (ILP) which was pioneered by Detroit Edison in the late 1990s.

GoodCents Select comprises four elements: (1) a TOU rate with a CPP component, (2) a smart meter that receives pricing signals and provides outage detection, (3) customer-programmed automated response technologies,¹⁹² and (4) multiple ways to communicate rate changes and critical peak conditions to participants. There are three TOU prices for non-critical hours, and a CPP that can be invoked no more than one percent of the hours in a year.¹⁹³

Some program highlights include:

- 7,200 Participants (2006)
- 96% Customer Satisfaction Rating
- 2006 Goal – 3,000 installations
- Incentive payments are imbedded in the four-part TOU tariff
- No penalties for failing to curtail
- Began moving into Multi-Family segment in 2006
- Customers pay a \$4.95 monthly charge for fully installed package (includes thermostat, surge protector, and automatic outage notification)

¹⁹¹ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 58). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

¹⁹² Including a smart thermostat governing air conditioning and water heaters, plus heat- and pool-pump timers.

¹⁹³ Federal Energy Regulatory Commission. (August 2006). *Assessment of Demand Response & Advanced Metering*. (pp. 58). Washington, DC: Author

<http://www.ferc.gov/legal/staff-reports/demand-response.pdf>

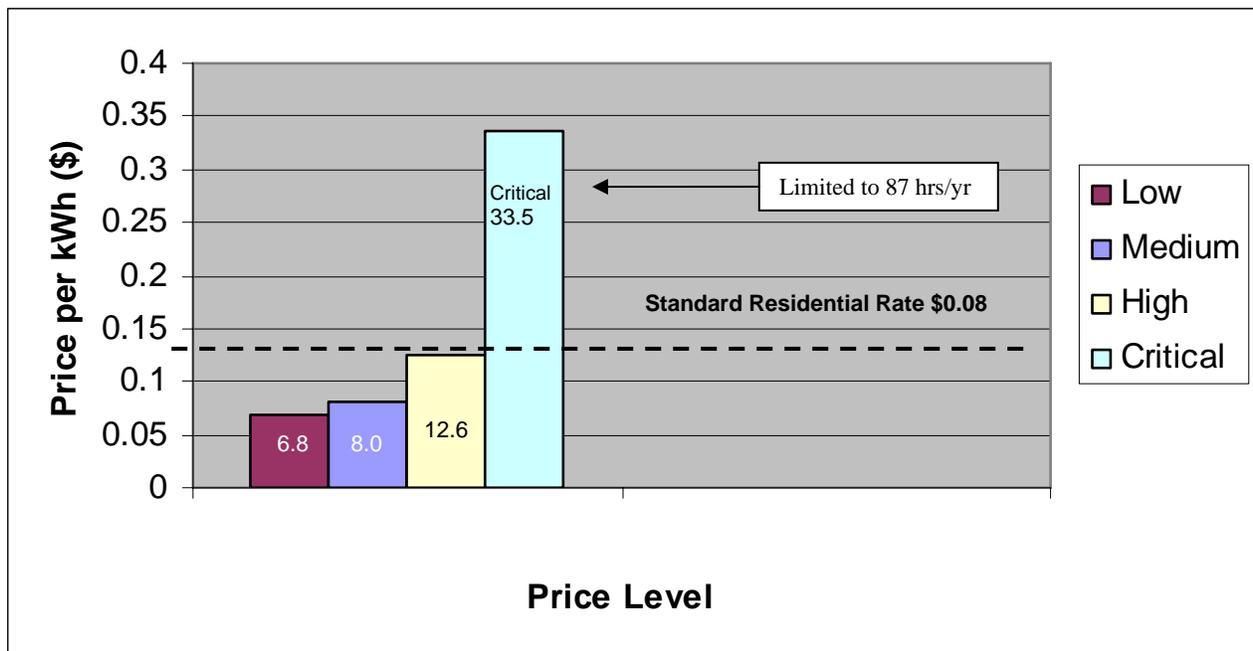
The program's rates structure incorporates a CPP rate structure.¹⁹⁴ The price per kWh (as of 01/01/07) is:

Price Level	Price per kWh	% Annual Hours in Effect
LOW	6.8 cents	28%
MEDIUM	8.0 cents	59%
HIGH	12.6 cents	12%
CRITICAL	33.5 cents	1% max

Source: Gulf Power

Graph 5-2 provides a graphical representation of GoodCents Select's CPP price structure.

Graph 5-2 GoodCents Select's CPP Price Structure



Source: January 2006 Presentation by Brian White, Staff Market Specialist (Gulf Power Company)

Key SPP findings related to the CPP effectiveness of Gulf Power's GoodCents SELECT:

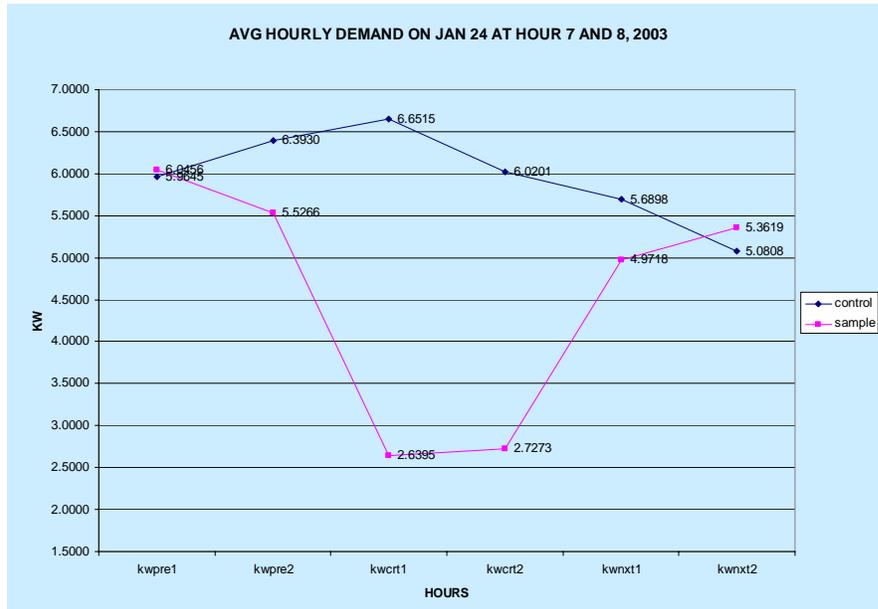
- Significant Real-Time demand reduction¹⁹⁵
 - Summer: reductions range from 1.66 to 1.89 kW, with average of 1.73 kW per residence
 - Winter: reductions range from 1.86 to 2.44 kW, with average of 2.2 kW per residence
- Customers save up to 15% on electricity bill annually

¹⁹⁴ For more information see GoodCents Select pricing periods at <http://www.gulfpower.com/residential/pdf/magnet.pdf>

¹⁹⁵ Phone interview with Brian White, *Staff Market Specialist* at Gulf Power Company

- Typical customers uses 3.8% less energy
- Historically customers do not exceed 30 hours Critical Pricing in a year. Technology gateway* programmed not to exceed 87 hours of Critical Pricing annually serves as hedge
- 1 hour notification prior to Critical Price implementation via indicator light on thermostat

Load Research results confirm demand reduction:



Source: January 2006 Presentation by Brian White, Staff Market Specialist (Gulf Power Company)

Pilot programs nationwide have confirmed that, when combined with customer education and enabling technology, CPP rates have the most dramatic impacts on load shifting. It is suggested that a CPP rate be tested as part of a Michigan Demand Response Pilot Program. This rate should be tested for both residential and C&I costumers, in conjunction with and without education

II. Real Time Pricing (RTP)

RTP programs have a long history. Seventy U.S. utilities at one time or another have offered RTP demand response programs.¹⁹⁶ These have been shown to be effective in encouraging load shedding, especially among residential customers.

Ameren Power Smart Pricing

The Illinois-based Ameren utilities have been successful at encouraging load shedding with the Power Smart Pricing program.¹⁹⁷ The Power Smart Pricing program is the successor to the 750

¹⁹⁶ From testimony delivered before the California Energy Commission on 4-19-07. See page 152 and http://www.energy.ca.gov/2007_energypolicy/documents/2007-04-19_workshop/2007-04-19_TRANSCRIPT.PDF

¹⁹⁷ See “About Power Smart Pricing” <http://www.powersmartpricing.org/about-power-smart-pricing.php>, “Benefits” <http://www.powersmartpricing.org/benefits.php>, and “Program Guide” <http://www.powersmartpricing.org/program-guide.php>.

* The gateway is the hardware that provided metering intelligence and enables two-way communication between Gulf Power and AMI meters installed in customers’ residences.

participant Energy-Smart Pricing Plan (ESPP) pilot program that ran from 2003-05.

Power Smart Pricing is a real-time pricing program for residential customers outfitted with smart meters. Ameren has contracted with CNT Energy, a nonprofit organization dedicated to helping people and communities manage energy costs. While Ameren continues to supply electric power and issues bills to customers participating in the Power Smart Pricing program, CNT Energy provides information, services and tools to help customers manage electricity costs with the Power Smart Pricing program.

Power Smart Pricing offers day-ahead notification of high price days (pilot price > \$0.10/kWh; now price > \$0.13/kWh) by email/phone. Day-ahead prices are posted on website or available by phone after 5pm. The program contains a price-protection cap (price limit hedge at \$0.50/kWh).

Customer bills include an access charge in addition to hourly prices. Currently customers pay a monthly fee of \$2.25 to participate in program. Charges are adjusted yearly, and are capped at 4.8¢ and 5.4¢ per kWh (single-family and multi-family households, respectively). Once enrolled, customers are committed to a mandatory twelve consecutive month hourly, market-based rate.

ESPP pilot program result highlights include:¹⁹⁸

- ESPP participants consumed 35.2 kWh less per month during summer months (average June to August of 2003-2005), a savings of 3 to 4% of summer electricity usage.
- An overall price elasticity of -4.7% was observed
- There was significant response to high-price notifications, with reductions in voluntary consumption going as high as 15%
- The automatic cycling of CACs during high-price periods added to response by as much as 2.2%, for total price response of 6.9%
- Average household savings are 10% per year

Georgia Power

Georgia Power, a subsidiary of Southern Company, runs what is believed to be the "world's largest RTP program."¹⁹⁹ The program has over 1,700 customers, peak demand [shedding] of nearly 5,000 MW, load drops in the 15-20% range, and 40-80% of the participants respond to the changing price levels.²⁰⁰

Under Georgia Power's RTP program customers are alternatively credited or charged for electricity usage below or above a pre-determined customer baseline load (CBL). Participants may choose to pay for these differences from their CBL based on either day-ahead or hour-ahead market pricing. Furthermore, customers may also select from a variety of price protection products, including caps,

¹⁹⁸ Summit Blue Consulting. (2005). *Evaluation of 2005 Energy-Smart Pricing Plan*. Boulder, CO: Author
http://www.icc.illinois.gov/e-docket/reports/view_file.asp?intIdFile=170715&strC=bd

¹⁹⁹ From testimony delivered before the California Energy Commission on 4-19-07. See page 151 and
http://www.energy.ca.gov/2007_energy/policy/documents/2007-04-19_workshop/2007-04-19_TRANSCRIPT.PDF

²⁰⁰ From Demand Response and Advanced Metering Coalition (DRAM) flyer found at
<http://www.dramcoalition.org/id54.htm>. Also testimony delivered before the California Energy Commission on 4-19-07. From testimony delivered before the California Energy Commission on 4-19-07. See page 152 and
http://www.energy.ca.gov/2007_energy/policy/documents/2007-04-19_workshop/2007-04-19_TRANSCRIPT.PDF

collars, contracts for differences, index swaps, and index caps. These variants on the basic real time pricing service are risk management tools that customers can use as a hedge during possible periods of higher real-time electricity prices.²⁰¹

Some key features of Georgia Power's RTP program include:

- Baseline usage based on historic demand, priced at embedded rates
- Incremental usage and decremental savings priced at RTP, calculated as sum of marginal energy costs, line losses, a "risk recovery factor" (a fixed adder), and, at peaks, marginal transmission costs and outage cost estimates
- Two options: day ahead and hour ahead
- Interruptible for some customers, penalties for failure to interrupt
- Predictable load response based on real-time prices charged

RTP send the most accurate price signals and have been shown to be very effective in shedding residential load. RTP rates should be tested as part of a Michigan Demand Response Pilot Program for both residential and C&I costumers, in conjunction with and without education.

III. Interruptible/Curtailable Rates

Interruptible/Curtailable Rates have been in existence for over thirty years. They have been a preferred tool for encouraging load-shedding because of the degree of direct control they provide utilities. Detroit Edison's own Interruptible AC (IAC) program is recognized nationwide for both the large number of participants and the amount of demand response resource it represents.

Expansions to current interruptible/curtailable rates should also be considered as part of a Michigan Demand Response Pilot Program. ***Interruptible/curtailable rates provide utilities with the greatest form of demand response control and predictability. The impact of these rates, when combined with AMI/enabling technology functionality (such as smart thermostat degree set backs), should be tested in Michigan.*** These rates should be tested for both residential and C&I costumers, in conjunction with and without education.

IV. TOU Rates

Salt River Project

The Salt River Project (SRP) is an Arizona-based utility. SRP's residential TOU program (E-26) is cited as having residential participation rates that approach one-third of their customers.²⁰²

²⁰¹ See "Energy-Efficiency Funds and Demand Response Programs, Georgia" http://www1.eere.energy.gov/femp/program/utility/utilityman_em_ga.html and "Georgia Power rates" http://www.georgiapower.com/pricing/gpc_rates.asp

²⁰² For detailed information see <https://www.srpnet.com/prices/home/tou.aspx> and page 55 of FERC's *Assessment of Demand Response & Advanced Metering*.

The E-26 price plan is for residential customers who use 1,000 kWh or more of electricity during the summer months and who can shift their usage to off-peak hours. Electricity is priced at two levels, depending on the time of day. Prices are lower during off-peak hours and higher during on-peak hours. See table 5-3 for detailed information on residential TOU rates. Both on- and off-peak hours change from summer to winter.

Table 5-3 SRP Residential TOU Rates

	Summer – May 1 to Oct 31	Winter - Nov 1 to Apr 30
On-peak	1 p.m. to 8 p.m. (weekdays)	5 a.m. to 9 a.m. (weekdays) 5 p.m. to 9 p.m. (weekdays)
Off-peak	All other hours, plus holidays*	All other hours, plus holidays*

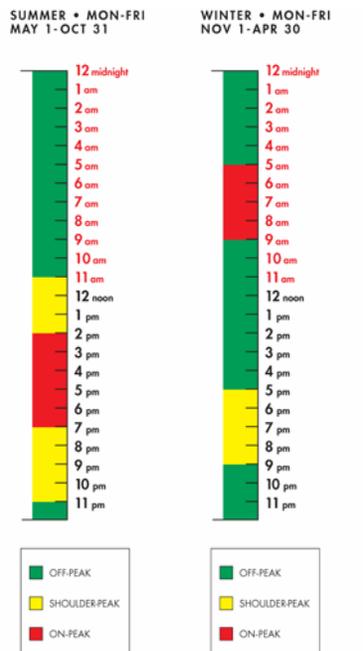
*New Year's Day, Memorial Day (observed), Independence Day, Labor Day, Thanksgiving Day and Christmas Day.

Source: Salt River Project

Switching to this price plan saves the typical customer an average of 8% off their annual energy bill.

SRP also has a business TOU program (E-32). This business TOU plan is an optional, three-period time-of-use plan. It has on-peak, shoulder-peak and off-peak pricing periods and is designed for customers with demands of at least 25 kW who are able to take advantage of the lower prices in the shoulder-peak and off-peak periods. Electricity is priced at three different levels depending on the time of day. See graph 5-3 for detailed information on business TOU rates. Approximately 85% of the summer hours are either lower-priced off-peak or shoulder hours.

Chart 5-2 SRP Residential TOU Rates



All weekend long is off-peak, during both summer and winter. Please note, regular Time-of-Use hours apply during weekday holidays on the E-32 Price Plan.

Source: Salt River Project

Enhanced, multi-tiered TOU rates should be tested to gauge impact on Michigan consumers. TOU rates should be tested as part of a Michigan Demand Response Pilot Program for both residential and C&I costumers, in conjunction with and without education.

V. Prepaid Energy

An emerging use of smart meters is in the sale of prepaid electricity. Pilot programs, like the one being currently run by the Sacramento Municipal Utility District, allow residential customers to buy electricity on a prepaid basis. This program is part of a growing trend in which U.S. utilities are experimenting with pay-as-you-go services that allow customers to monitor their own energy use and which encourage energy conservation. The idea being that if more people paid for electricity in advance, like they do for gasoline, they might want to make it stretch further and as such will exhibit more price elasticity during critical periods. Experts say people quickly learn to ration their use, just as people learn to eliminate unnecessary car trips when gasoline is expensive.

Participating customers buy credit which is loaded on to a “smart card.” The smart card is then used to download information into the home electric meter. With the help of a user display terminal (UDT) – an electronic display connected to the AMI - participants can keep track of the credit balance, energy consumption, and cost of running individual home appliances.²⁰³ The UDT gives customers a very tangible look at how much electricity they are using on a daily basis. They can review consumption patterns by day, week, or month, and can even switch to real-time consumption, which can give them a better understanding of how much it costs to run various home appliances.²⁰⁴

A half-dozen utilities are trying prepaid programs now. This trend could accelerate quickly if Texas utility regulators approve rules this summer allowing it in their state.²⁰⁵ Salt River Project, a Phoenix utility, has the largest prepaid program (M-POWER) in the U.S. with 55,000 of its 920,000 metered customers (some 5.98%) enrolled in the program.²⁰⁶

Aside from the demand side benefits to prepaid electricity, the concept of prepaid service is gaining support among utilities because it can help relieve accounts-receivable problems (when customers consume more energy than they can afford). With prepaid service, the customer is in control and doesn't face a monthly surprise when the bill arrives.²⁰⁷

In the next few years, some experts expect prepaid electric service to become a standard feature of U.S. utilities, as it already is in the U.K., China and South Africa.²⁰⁸

At best prepaid energy programs are only likely to make a marginal contribution to peak load reduction. While mainly seen as having energy efficiency applications, a prepaid energy program may be leveraged to promote demand response. Marketed to Michigan's most cost-conscious residential consumers (those most motivated to keeping track of consumption on a regular basis,

²⁰³ Davis, K. (2003). Prepaid Metering Can Bring Strays Back to Your Fold. *Utility Automation & Engineering T&D*. Retrieved July 2007 from http://uaelp.dev.pennnet.com/articles/article_display.cfm?article_id=177014

²⁰⁴ Ibid.

²⁰⁵ New Ways to Monitor Your Energy Use. (2007, June 19). *The Wall Street Journal*, p. D1

²⁰⁶ For more information about SRP's M-POWER program see <http://www.srpnet.com/payment/mpower/default.aspx>

²⁰⁷ New Ways to Monitor Your Energy Use. (2007, June 19). *The Wall Street Journal*, p. D1

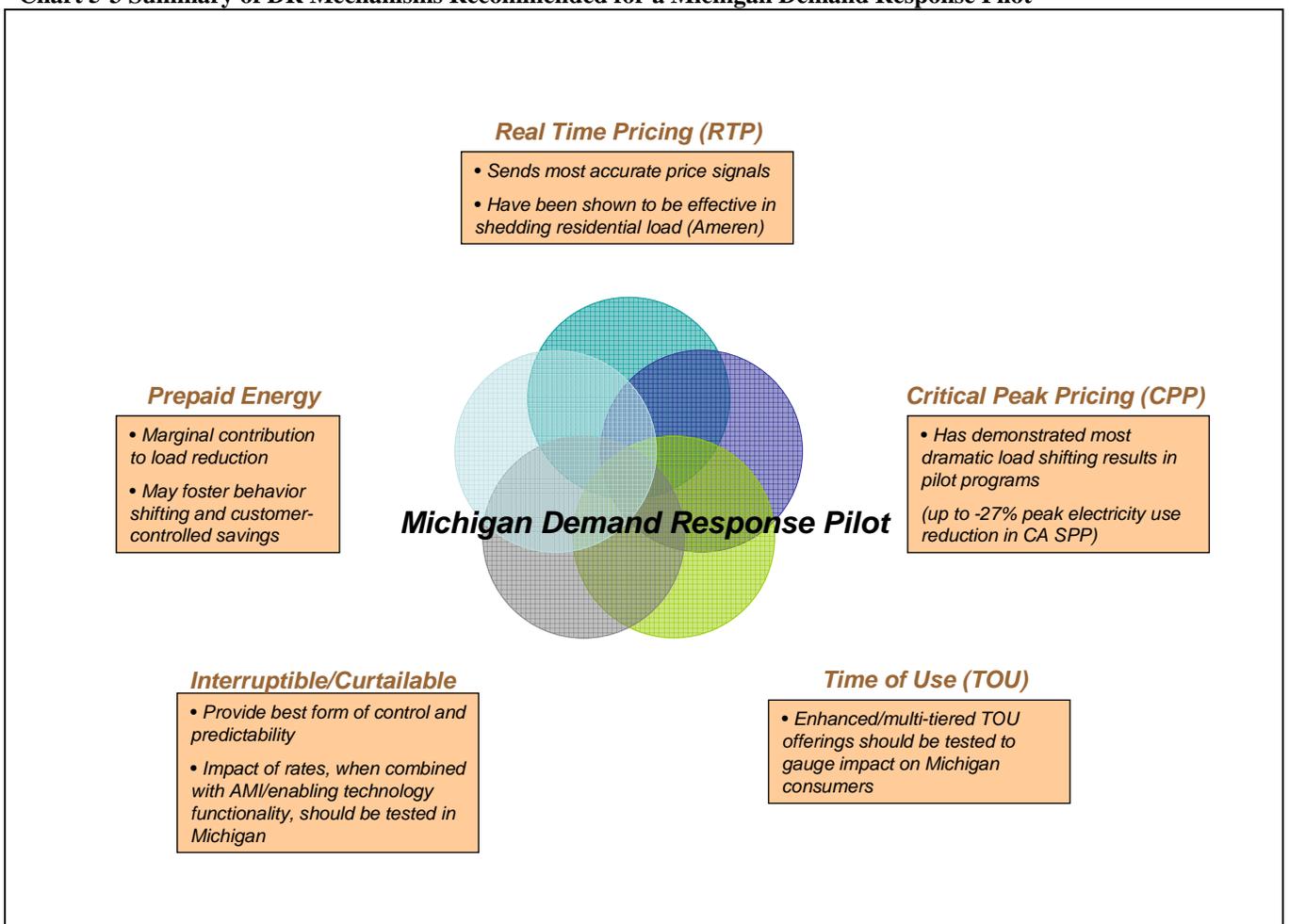
²⁰⁸ Ibid.

and as such more likely to respond) *a prepaid energy program may promote behavior shifting and customer controlled savings. When combined with an appropriate time of use tariff, a prepaid energy program could be leveraged to achieve demand response load shedding goals.* For instance a customer’s prepaid credits could be consumed at a CPP rate during critical periods of summer demand.

A small prepaid energy program for residential customers should be recommended as part of Michigan’s Demand Response Pilot Program.

Chart 5-3 summarizes the demand response mechanism recommended for a Michigan Demand Response Pilot.

Chart 5-3 Summary of DR Mechanisms Recommended for a Michigan Demand Response Pilot



SECTION 6: STRATEGIC CONSIDERATIONS

A successfully implemented demand response program can provide operational and capital cost savings to LSEs and system operators. Financial benefits come from avoided generation expenses, deferred transmission and distribution costs, and improvements in operational efficiencies. In addition to said financial and operational benefits, developing an effective demand response program may impact a utility's competitive advantage.

1. Strengthen Position as Low Cost/Reliable Competitor

Electric utilities provide an undifferentiated product. Michigan LSEs compete in a hybrid market with increased retail competition, especially for large customers. Michigan LSEs must rely on providing great customer service and a reliable product, at a low cost. A well-marketed and well-executed demand response program, one that includes a comprehensive customer education component, can reinforce the perception that a utility is working to lower costs (helping customers save money today and avoid/reduce future rate increases) while improving reliability.

2. Improve Customer Satisfaction By Facilitating the Automation of DR

Being strategic about the customer service options related to demand response can make a big difference to customer satisfaction. For instance, many utilities manage energy efficiency and demand response programs separately from customer service. As a result these utilities take a mass market approach to customer education and program promotion. Customers often receive price signals (via the internet and other channels) at times when they are not receptive. Program promotion yields are therefore expensive for the results gained.

LSEs that use technology to address customers at the key times when they are thinking about the utility (e.g. when they get the electricity bill), that help customers connect demand response to their own bills, and that provide linkages/automation to suggested actions, may gain a competitive advantage through increased customer satisfaction.

3. Branding Opportunities

Deployment of a demand response program may have other impacts on a utility's competitive position. Shifts to demand response tariffs may imply a host of changes to the customer-supplier relationship, including new forms of and interest in usage data and more active management of the utility-customer relationship.

Because they are seen as premium or upgrade products, programmable thermostats and other enabling devices are attractive to both owners and occupants. Through the installation of AMI and other enabling technologies a demand response program may give a utility the opportunity to make their brand visible right inside a customer's home. For instance, placing an LSEs company logo on enabling hardware (e.g. a home display or smart thermostat) could improve the chances that customers will associate the LSE with responsible energy stewardship and innovation.

4. AES's Role in Demand Response

A still unanswered question is what sorts of obligations AES's will have to participate in a pilot program. What role should they play in the planning and implementation of demand response pilot programs? This is an important strategic consideration given Michigan's hybrid electricity market.

SECTION 7: PILOT PROGRAM IMPLEMENTATION

I. Purpose of Demand Response Pilot Program

The purpose of a demand response pilot program is to obtain information needed to determine how dynamic pricing (time-based rates), coupled with enabling technology (AMI meters, smart thermostats, etc.), can be made beneficial to a utility and electricity consumers in Michigan. Specific goals and objectives to consider are:

1. To estimate the energy and demand savings associated with moving customers (residential, commercial, and industrial) from standard rates to experimental time-of-use with a critical peak pricing (CPP) component.
2. Pilot programs should be designed to determine the magnitude of load reduction during the on-peak period, the magnitude of the load reduction during the CPP periods, and the amount of energy shifted from on-peak to mid-peak or off-peak periods.
3. Examine the impact of coupling the experimental TOU rate with the CPP component with enabling technology (AMI).
4. Determine peak period demand (kW) impacts associated with various pricing structures.
5. Survey program participants to determine ways to improve on demand response offerings.
6. Examine the cost-effectiveness of this type of program.
7. Correlate customer profiles (demographics, energy usage, etc.) with likelihood of participation in demand response program.
8. Calculate price elasticity of demand for various pricing structures.
9. Use data gathered to develop solid recommendations for augmenting a utility's current demand response offerings.

II. Pre-Pilot Focus Groups

Hosting a pre-pilot customer focus group may offer insights that prove to be valuable in the design of the pilot program. Some of the key objectives of holding focus groups may include:

1. Understanding level of customer knowledge about electricity business.
2. Determine customer's willing level of involvement.
3. Get price points (i.e. determine how much savings will incentivize customer participation).
4. Get sense of what non-time critical activities customers would be willing to put off (e.g. "how much would you put off AC on the hottest day?")
5. Determine most effective methods/channels for conveying price signals to customers.

III. Pilot Roll Out

In preparing to execute a demand response pilot program the following decisions should be made:

1. The experimental rate offerings/other programs that will be tested
2. Enabling technologies that will be tested
3. Decide on AMI technology platform and create AMI deployment plan

4. Experimental Design²⁰⁹
5. Geographical Constraints
6. Target Population
7. Sample Design
8. Customer Recruitment and Market-potential Study design
9. Event Trigger
10. Control Strategy
11. Customer Notification
12. Customer Billing
13. Analysis of barriers to implementation, and mitigation
14. Customer Participation Analysis Plan

In addition to the items listed above, the programmatic, financial, operations infrastructure needed to initiate and administer a demand response pilot should be established.

²⁰⁹ A challenge faced by designers of demand response programs is to develop compelling value propositions to recruit customers that will provide the levels of load that achieve these market benefits. Three types of design criteria (designed to get customer buy-in) may be described as: (1) **participant criteria** that determine attractive customer characteristics, (2) **operations criteria** by which the load resource is called or dispatched, and (3) **settlement criteria** describing the financial arrangements. For more information see *Demand Response: Design Principles for Creating Customer and Market Value* prepared by the Peak Load Management Alliance at <http://www.peaklma.com/files/public/CustomerPrinciples.pdf>

SECTION 8: CONCLUSION

Demand response is increasingly important to utilities and may have important impacts on their financial performance, customer satisfaction, regulation, and has other implications for competitive advantage. Detroit Edison is moving in the direction of establishing robust demand response programs and is in a position to play a leading role in driving the policy innovations and technological advancements.

There are many demand response options for Detroit Edison to experiment with. Calculating the effectiveness of a demand response program is based on a combination of statistical estimation and engineering analysis. Currently there is no consistency in these methods across utilities, states, and ISOs. In its drive to develop a robust demand response portfolio Detroit Edison will need to work with state regulators and other LSEs to settle on common standards for measuring the effectiveness of future demand response programs in the state.

AMI technology promises to provide essential analytical tools that will greatly enhance the ability to execute demand response programs. Many issues surrounding AMI standards, costs, and benefits remain unresolved. Finding innovative ways of leveraging AMI technology to automate demand response is key to AMI's future as an enabler of demand response.

Most electricity customers, particularly residential, resist demand response programs that require effort, and as such the basic design of a demand response program should be simple. Technology products that enable and automate demand response must be included in any program, and the costs of these are often subsidized by LSEs.

State legislators, regulators, and utility executives have many important choices to make in order to create robust demand response programs in Michigan. Among issues to be addressed are:

- **Regulatory barriers**, including the disconnect between retail and wholesale prices, and revenue disincentives imbedded in current rate structures that prevent utilities to implement demand response programs. In addition, a fair AMI cost recovery methodology must be developed. Without one utilities will not invest in the AMI technology that can enable demand response.
- **Demand response effectiveness measures**, including the development of widely accepted and consistent M&V methodologies and cost-effectiveness tests. Developing tools that accurately measure customer uptake rates (such as the DRMP methodologies discussed on page 21 of this report), is imperative.
- **Uncertainty about AMI meters**. According to analysis done by KEMA, many utilities are waiting for industry standards before selecting AMI technology solutions. Lingering interoperability issues and the uncertainty about technology, costs, and benefits of AMI also remain significant barriers to future adoption.

There are no simple, one-size-fits-all approaches to rolling out a scalable demand response program. Detroit Edison and the members of the Michigan Demand Response Collaborative will need to assess the differing needs of each LSE's jurisdiction in order to craft the most effective program.

APPENDECIES

Appendix A – Measured Benefits and Costs of Demand Response Cost-effectiveness Tests

Participant Test – This test measures the quantifiable benefits and costs to the *customer* from participation in a program. As many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

- **Measured Benefits:** The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross²¹⁰ savings, as opposed to net energy savings.
- **Measured Costs:** The costs to customers are the out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure.
- **Expression of Test Results:** The results of this test can be expressed in four ways: as the net present value (NPV) per average participant, a NPV for the total program, a benefit-cost ratio or discounted payback. The primary means of expressing test results is NPV for the total program; discounted payback, benefit-cost ratio, and per participant NPV are secondary tests.
- **Other Notes:** This test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates. The test can also be used for program design considerations such as determining the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation.

Ratepayer Impact Measure (RIM) Test – This test measures what happens to customer bills or rates due to *changes in utility revenues and operating costs caused by the program*. Rates will go down if the change in revenues from the program is greater than the change in utility costs. As such this test indicates the direction and magnitude of the expected change in the customer bills or rate levels.

- **Measured Benefits:** The customer benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in

²¹⁰ *Gross* energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program. For fuel substitution and load building programs, gross-to-net considerations account for the impacts that would have occurred in the absence of the program. (For more information see page 8 of CALIFORNIA STANDARD PRACTICE MANUAL: ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS found at WWW.ENERGY.CA.GOV/GREENBUILDING/DOCUMENTS/BACKGROUND/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF)

transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased.

- Measured Costs: The costs for this test are the program costs incurred by the utility, and/or other entities incurring costs and creating or administering the program, the incentives paid to the participant, and decreased revenues for any periods in which load has been decreased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value).
- Expression of Test Results: The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW, therm, or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW, therms, or customer); benefit-cost ratio; and net present value.
- Other Notes: This is the only test that reflects the revenue shift (from ratepayers to utility) that arises as a result of revenues lost due to demand response program. Test can be used for all demand-side management programs (conservation, load management, fuel substitution, and load building), making it particularly useful for comparing impacts among management options

Utility Cost Test (UCT) aka Program Administrator Cost (PAC) Test – This test measures the net costs of a demand-side management program based on the costs incurred by the program administrator and excluding any net costs incurred by the participant.

- Measured Benefits: The benefits calculated by this test include avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction.
- Measured Costs: The costs calculated by this test include program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased.
- Expression of Test Results: The results of this test can be expressed either as a net present value, benefit-cost ratio, or levelized costs. The net present value is the primary test, and the benefit-cost ratio and levelized cost are the secondary tests.
- Other Notes: This test shares two limitations noted previously for the Total Resource Cost test: (1) by treating revenue shifts as transfer payments, the rate impacts are not captured, and (2) the test cannot be used to evaluate load building programs.

Total Resource Cost Test (TRC) – This test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participant's and the utility's costs.

- Measured Benefits: The benefits calculated by this test include represent the combination of the effects of a program on both the customers participating and those not participating in a program. The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction.
- Measured Costs: The costs in this test are the program costs paid by both the utility and the participants, plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them,

are included in this test. Any tax credits are considered a reduction to costs in this test.

- Expression of results: The results of the Total Resource Cost Test can be expressed in several forms: as a net present value, a benefit-cost ratio, or as a levelized cost.
- Other Notes: Test results are unaffected by the uncertainties of projected average rates (because test treats incentives paid to participants and revenue shifts as transfer payments - from all ratepayers to participants through increased revenue requirements), thus reducing the uncertainty of the test results.

See Appendix A (page 26) in CALIFORNIA STANDARD PRACTICE MANUAL ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS ²¹¹for appropriate **guidelines** for developing **the primary inputs** for **the cost-effectiveness equations** for four tests described above.

²¹¹ This manual can be found at http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

Appendix B - Methods of Estimating Demand Response Penetration Rates

Method	Description	Advantages	Issues/Questions
Delphi (expert judgment)	Solicit estimates from a panel of individuals with experience or insight	Relatively simple method which may provide reasonably accurate estimates	<ul style="list-style-type: none"> • Results are subjective—what constitutes an expert? • Requires a method of resolving divergent estimates
Translated experience	Use actual participation rates for demand response programs implemented for similar market segments or target populations, and/or in markets with similar supply conditions and market structure	<ul style="list-style-type: none"> • Uses actual data on realized penetration rates of implemented demand response options • Depending on the data source(s), can provide detailed estimates 	<p>Assumes that the customers, market segments, market supply conditions and other characteristics of the population on which estimates are based are identical and directly translatable to the population to which the estimates are applied.</p> <p>Potential sources of bias include:</p> <ul style="list-style-type: none"> • the method of setting prices/incentives • the level and volatility of prices/incentives • the market structure (e.g., organized market with ISO/RTO vs. vertically integrated utility in region without ISO) • differences in the customer base (e.g., different types of manufacturing facilities in different regions) • differences in customer experience with load management and demand response • climatic differences
Benefit threshold	Set a minimum level of economic benefits required for a customer to participate (e.g. payback time)	Logical theoretical basis for modeling customer participation	<ul style="list-style-type: none"> • Requires a subjective determination of how high the benefit threshold should be set for different customer market segments and/or individual customers as well as estimates of demand response costs • Assumes that customers act rationally—in reality, not all customers will choose to participate, even if it benefits them
Choice model	Develop a statistical model of the factors that drive customer participation, using data from demand response programs implemented for similar market segments or target populations, and/or in markets with similar supply conditions	<ul style="list-style-type: none"> • Provides a robust statistical method for estimating participation at a fine level of detail • Uses actual data on customer participation from implemented demand response programs 	<p>Assumes that the customers, market segments, market supply conditions and other characteristics of the population on which estimates are based are identical and directly translatable to the population to which the estimates are applied.</p> <p>Potential sources of bias include:</p> <ul style="list-style-type: none"> • the method of setting prices/incentives • the level and volatility of prices/incentives • the market structure (e.g., organized market with ISO/RTO vs. vertically integrated utility in region without ISO) • differences in the customer base (e.g., different types of manufacturing facilities in different regions) • differences in customer experience with load management and demand response • climatic differences
	Develop a statistical model of the factors that drive customer participation, using survey data on expected choices by the population of interest	<ul style="list-style-type: none"> • Provides a robust statistical method for estimating participation at a fine level of detail • Uses data obtained from a sample of customers in the target population 	<ul style="list-style-type: none"> • Customers survey responses based on hypothetical options may differ from their actual behavior when faced with real choices • Surveys can be resource-intensive

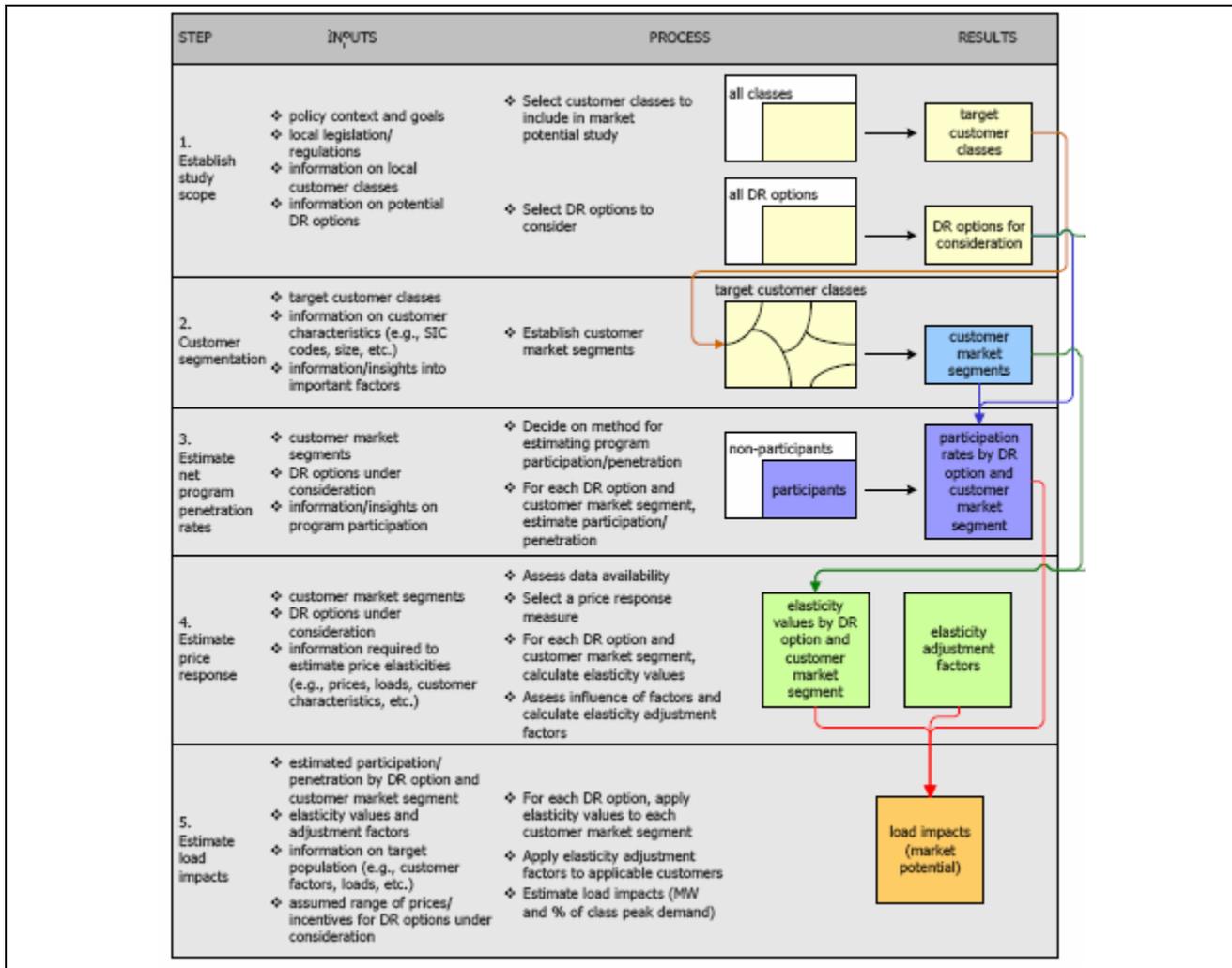
Source: LBNL “Estimating Demand Response Market Potential among Large Commercial and Industrial Customers”

Appendix C – Factors Influencing Customer Response to Demand Response Programs

Factor	Description	Impact on Response
EXTERNAL FACTORS		
Event duration	<ul style="list-style-type: none"> • Duration of individual events (e.g., in hours) 	<ul style="list-style-type: none"> • Some customers may not respond unless high hourly prices or incentives are applicable for a block of several hours • Some customers may be unwilling to curtail for long periods (e.g., more than four to six hours)
Event frequency	<ul style="list-style-type: none"> • Overall frequency of events in a particular season 	<ul style="list-style-type: none"> • If events occur too frequently, customers may be unwilling or unable to continue load curtailments (this is known as “response fatigue”) • Conversely, experience gained from multiple events can enable customers to fine-tune their curtailment strategies
Event clustering	<ul style="list-style-type: none"> • Distribution of events over time (e.g., clustered on consecutive days vs. isolated incidents) 	<ul style="list-style-type: none"> • Clustered events may cause “response fatigue”—reduced willingness or ability of customers to respond
Weather	<ul style="list-style-type: none"> • Temperature and humidity are strong drivers of HVAC usage • Increased HVAC usage drives overall system demand and prices 	<ul style="list-style-type: none"> • Weather-sensitive loads (e.g. air conditioning) may be somewhat discretionary; some customers may respond more when prices are high or system emergencies are perceived • Conversely, some customers may be unwilling to reduce or curtail air conditioning loads during prolonged or extreme weather events
CUSTOMER-SPECIFIC FACTORS		
Training, awareness and past experience	<ul style="list-style-type: none"> • Past participation in similar demand response programs or tariffs, or experience managing energy commodity risk (e.g. gas markets) • Attendance at training workshops • Technical audits or information 	<ul style="list-style-type: none"> • May enhance customers’ acceptance of demand response options and ability to respond
Onsite generation	<ul style="list-style-type: none"> • The presence of onsite generation equipment (e.g., backup generators, gas turbines, fuel cell or renewable generation technologies) at customers’ facilities 	<ul style="list-style-type: none"> • Subject to environmental regulations, onsite generation allows customers to respond without interrupting electric end uses • Provides customers with more response flexibility
Enabling technologies	<ul style="list-style-type: none"> • Energy management controls systems (EMCS)—provide customers with the means to program equipment (e.g., HVAC or lighting control systems) usage changes in response to demand response events • Energy Information Systems (EIS)—allow customers to analyze their load usage patterns, establish their baseline energy usage, access information about demand response events or prices, and identify strategies for load curtailment 	<ul style="list-style-type: none"> • EMCS and EIS can help improve the persistence and sustainability of load curtailments, and provide immediate feedback to customers on load curtailment performance
Electricity intensity	<ul style="list-style-type: none"> • Electricity costs as a share of customers’ operating expenses 	<ul style="list-style-type: none"> • Customers whose operations are highly electricity-intensive may be more likely to participate in and respond to demand response options in order to minimize costs • Conversely, high-intensity users may view their electrical end uses as non-discretionary, making them less likely to participate or respond
Business or operational processes	<ul style="list-style-type: none"> • Features of customers business processes that impact the flexibility of their response (e.g., industrial process equipment, three-shift operations, facilities at multiple geographic locations) 	<ul style="list-style-type: none"> • Certain types of industrial customers that can shift usage by rescheduling industrial processes (e.g., batch processes) or equipment usage (e.g., arc furnaces, aluminum smelters) may be more price responsive

Source: LBNL “Estimating Demand Response Market Potential among Large Commercial and Industrial Customers”

Appendix D – Steps for Estimating Demand Response Market Potential



Source: LBNL “Estimating Demand Response Market Potential among Large Commercial and Industrial Customers”

**Appendix E – AMI Data Collection Technologies and Vendors
(Selected by Utilities participating in 2007 KEMA, Inc. Survey)**

Utility	Technology Selected (if determined) or System Planned	Vendor Selected (if determined)
Baltimore Gas & Electric	AMI: Not yet announced	Using Comverge for programmable thermostats; others TBD.
CenterPoint Energy	AMI: RF (point to point) Backhaul: BPL Short haul to endpoint: RF (point to point) CenterPoint has teamed with IBM Global Business Services to develop an architecture that uses substations as hubs, with BPL connections radiating out along medium-voltage distribution lines and connecting with Itron OpenWave meters	AMI: Itron
Consolidated Edison	AMI: RF (Mesh and Point-to-Point) Backhaul: TBD Short haul to endpoint: RF	TBD
DTE Energy	Fixed network; company has stated that a scalable and flexible MDM system is a critical component that should be installed as a precursor to AMI	MDM software: EnergyICT's EIServer®
PEPCO / Delmarva	1. AMI 2. Distribution Automation 3. Smart Thermostats linked to AMI 4. Improved Communications Network 5. MDM (CIS will eventually need to be replaced, but not as part of this Blueprint of the Future program)	Sensus SmartMeters
Pacific Gas & Electric	AMI: BPL and RF; PLC technology to retrieve meter data and a fixed RF network for the collection and transmission of daily gas usage data	DCSI for electric modules and network and Hexagram, Inc. for gas meter modules and network (both subsidiaries of ESCO Technologies Inc); Wellington Power Corp. of Pittsburgh, PA to install SmartMeter™ devices and network equipment; WACS, LLC of Minneapolis, MN for AMI IT Interface System; and IBM of Armonk, NY for project management and system integration. DCSI has agreed to deliver to PG&E versions of its newly developed TNG software as they become available and are tested. Delivery of the final version for which DCSI has committed is currently anticipated in the fourth quarter of fiscal 2007.
Portland General Electric	TBD Backhaul: TBD Short haul: RF and PLC	Undetermined; conducted RFP in late 2006 and still in negotiations with vendors.

Source: KEMA, Inc.

Appendix E – AMI Data Collection Technologies and Vendors (cont.)

San Diego Gas & Electric	AMI, BPL, substation automation programs, field SCADA switch rollout program, advanced transmission conductors, and sensor exploratory demonstration projects. AMI is an important and foundational building block for SDG&E's long term operating vision. Short haul to endpoint: Undetermined, but most likely will be PLC or RF.	TBD
Southern California Edison	AMI: Has required that all vendors use ZigBee chip Backhaul: TBD--testing multiple WAN integrated backhaul options	SCE is testing BPL equipment on its system by conducting a field trial with Current Technologies in a small area surrounding SoCal Ed's headquarters in Rosemead, California
Southern Company	AMI: RF MDM Short haul to endpoint: RF (point to point)	Sensus FlexNet®
TXU	BPL: 2,000,000 meters AMI: 1,000,000 meters	AMI: DCSI (265,000 meters) Landis+Gyr
WE Energies	AMI: RF (1.5 way and 2 way) Distribution automation	Distribution automation: Cooper Power Systems
Xcel Energy	AMI: RF MDM: EnergyICT (20,000 C&I customers currently, expected to be rolled out system wide) Backhaul: TBD	AMI: Cellnet and Itron

Source: KEMA, Inc.

Appendix F - Key AMI Organizations and Vendors

AMI Organizations	
Organization	Link
AMRA	www.amra-intl.org
International Utilities Revenue Protection Assoc (IURPA)	www.iurpa.org
Demand Response and Advanced Metering Coalition (DRAM)	www.dramcoalition.org

Source: Mid-Atlantic Distributed Resources Initiative (MADRI)

Major AMI Companies	
Organization	Link
AMDS	www.amdswireless.com
Amron	www.amronm5.com
Badger Meter	www.badgermeter.com
Cannon Technologies	www.cannontech.com
Cellnet	www.cellnet.com
Comverge	www.comverge.com
DCSI	www.twacs.com
Echelon	www.echelon.com
Elster	www.elstermetering.com
eMeter	www.emeter.com
ETG	www.etgroup.us
Hexagram	www.hexagram.com
Hunt Power/MeterSmart	www.metersmart.com
Hunt Technologies	www.turtletech.com
Itron, Inc.	www.itron.com
Landis + Gyr	www.landisgyr.com
Nertec	www.nertec.com
Sensus Metering Systems	www.sensus.com
Silver Spring Networks	www.silverspringnetworks.com
SmartSynch	www.smartsynch.com
Tantalus Systems Corp	www.tantalus.com
Telenectis	www.telenetics.com
Transdata	www.transdatainc.com

Source: Mid-Atlantic Distributed Resources Initiative (MADRI)

Appendix G – AMI Project Costs

Utility	Projected AMI Project Costs (total)
Con Edison	\$892 million
Baltimore Gas & Electric	\$400 million
CenterPoint	\$1.8 billion
Southern Company	\$280 million
Pepco	\$128 million
San Diego Gas & Electric	\$574 million
Pacific Gas & Electric	\$1.7 billion
Southern California Edison	\$1.3 billion
Portland General Electric	\$130 million

Source: KEMA, Inc.

Appendix H - Data Sources for LBNL Market Potential Simulation

DR Option	Data Source(s)	Eligible Customers (peak demand)	Available Data Range	Reference
Optional hourly pricing	Central and Southwest (CSW) Utilities' (now American Electric Power) two-part RTP rate	> 1,500 kW	1998–2002 (summers)	Boisvert et al. (2004)
Default hourly pricing	Niagara Mohawk Power Corporation (NMPC), a National Grid Company, SC-3A tariff	> 2000 kW	2000–2004 (summers)	Goldman et al. (2005)
Short-notice emergency program	NYISO Emergency Demand Response Program (EDRP)	> 100 kW	2001, 2002, 2005	Neenan et al. (2003)
	ISO-NE Real-Time Demand Response (RTDR) Program	> 100 kW	2003, 2005	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Price-response event program	ISO-NE Real-Time Price Response (RTPR) Program	> 100 kW	2003, 2005	RLW Analytics and Neenan Associates (2003, 2004 and 2005)
Critical-peak pricing	California Utilities Critical Peak Pricing Program	> 200 kW; > 100 kW for SDG&E	January 2003 to September 2004	Quantum Consulting, Inc. and Summit Blue Consulting, LLC (2004 and 2006)

Source: “Estimating Demand Response Market Potential among Large Commercial and Industrial Customers: A Scoping Study,” page 29

About California Utilities: Pacific Gas & Electric (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) offer a critical-peak pricing tariff to large customers. The tariff design is quite different from that of the California Statewide Pricing Pilot that primarily targeted residential customers (Charles River Associates 2005), and the resulting customer response is correspondingly different