Applied Energy Group

STATE OF MICHIGAN DEMAND RESPONSE POTENTIAL STUDY

Technical Assessment

September 29, 2017

Report prepared for:
THE STATE OF MICHIGAN

Energy Solutions. Delivered.

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EXECUTIVE SUMMARY

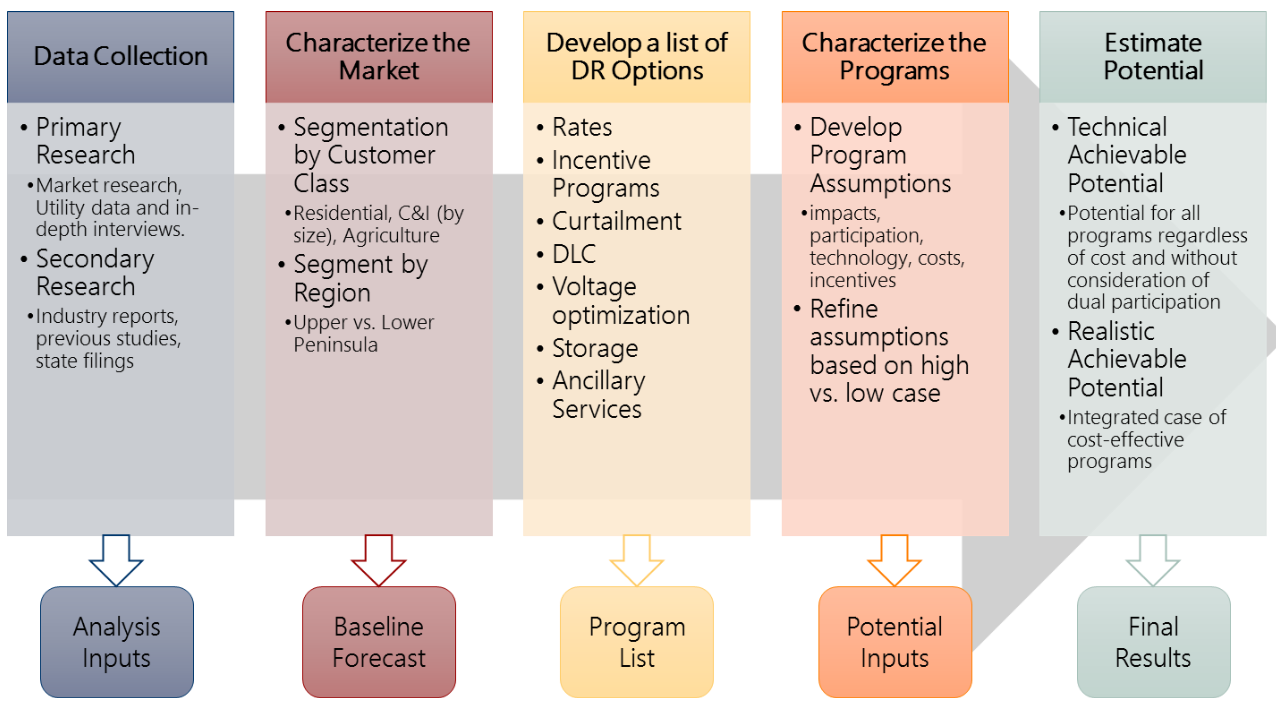
On December 21, 2016, Michigan's new energy plan was signed into law. As part of this new legislation, the Michigan Public Service Commission (MPSC) and Michigan Agency for Energy (MAE) were directed to engage in several new initiatives including a Statewide Assessment of Demand Response (DR) Potential. Demand response programs can reduce load on the electric grid during the highest times of usage (peak demand). The results of the potential study can be used to evaluate the utilities' progress in implementing their existing demand response programs and to serve as guidance for opportunities to expand their existing portfolios. In addition, this quantitative estimate of demand response potential will be used as an input for the state's integrated resource planning processes.

In accordance with this directive, the MPSC and the MAE engaged Applied Energy Group (AEG) and subcontractor DNV-GL to conduct a DR potential study for the State of Michigan. This study evaluates various categories of electricity DR resources in the residential, commercial, industrial, and agricultural sectors statewide for the years 2018-2037. The resource categories investigated include: direct load control, storage, demand side rates or incentive programs, curtailment agreements, voltage optimization, and ancillary services.

Overview of AEG's Approach to the Study

AEG used a rigorous and well-tested analysis approach for this study. Figure E-1 presents an overview of our approach to estimating DR potential in this study.

Figure E-1 Overview of AEG's Approach to Estimating DR Potential



Each box in the figure above corresponds to a key step in the study. Each arrow points to a corresponding key study element which drives the analysis toward the final results. The steps and key elements are described below.

- Data collection for this study consisted of both primary and secondary research. The primary research included a residential customer survey to assess attitudes toward demand response programs and collect information on appliance saturations within homes. It also included in-depth interviews with both DR providers and utility staff. Secondary research included reviewing reports, past potential studies, filings, and other publicly available information. We also collected data from the utilities regarding their current load characteristics, programs, and customer base. The data-collection process yields many of the key analysis inputs, which allows us to characterize the DR programs included in the study and develop our baseline forecast.
- The market characterization is important because it frames the space in which the study will take place and defines the customer groups which the study will investigate. It established which customer classes are included, and determines if there are any additional segments of interest. It incorporates the utility data provided during the data collection effort and develops a baseline forecast of demand by segment over the study horizon.
- Before we can estimate DR potential, we must generate a list of DR program options and assess their applicability to the market as characterized in the previous step. The outcome of this step is a finalized list of DR program options which are included in the study.
- Next, we characterize each of the DR programs in our list, using the best available information to describe the program as it might be implemented and estimate program impacts, participation, and costs. This step yields the inputs to the potential analysis that results in estimates at each level of potential.
- Finally, we bring it all together to estimate the technical achievable, and realistic achievable potential for the set of programs we characterized across the entire state. The entire process was designed to meet each of the study's key objectives.

Potential Results

For this study, we defined three types of potential which we believe lead to meaningful conclusions and recommendations regarding future DR:

- Technical Achievable Potential – Stand-Alone Case. Technical achievable potential represents an upper, realistic bound for potential DR attributable to each individual program without consideration of whether the program is cost effective or not. These individual potential estimates cannot be added together since the case also does not account for participation in multiple programs.
- Economic Screen. Each program is assessed for cost-effectiveness using a benefit-cost ratio. The cost-effectiveness of individual programs is assessed in each forecast year until the first cost-effective year is identified. Demand savings are realized only in cost-effective years.
- Realistic Achievable Potential. In the realistic achievable cases only cost-effective programs are considered. In addition, the integrated case accounts for participation in multiple programs and eliminates double counting. The study developed two levels of achievable potential.

IMPACTS ARE INCREMENATL:

It is very important to note that all estimates of DR potential presented in this study are incremental to the existing and forecasted DR from programs that are currently being implemented in the state.

- Realistic Achievable Potential – Integrated Low Case. The low case uses input assumptions that have lower participation rates, lower penetrations of enabling technology, lower costs, and opt-in rate programs.
- Realistic Achievable Potential – Integrated High Case. The high case uses input assumptions that have higher participation rates, higher penetrations of enabling technology, higher costs, and opt-out rate programs.

Key Considerations

The following list describes the key considerations which will provide context for the reader in reviewing the potential results:

- Estimates are incremental. In all cases, potential estimates are incremental to programs already implemented by utilities within the state of Michigan. When looking at overall potential, it is important to keep in mind that Michigan already has a significant amount of DR. The existing and forecasted capacity of programs is presented in Chapter 3.
- Technical potential estimates are standalone. Technical potential estimates represent individual estimates for each program and do not account for double counting. These should be viewed as independent estimates of potential for each program regardless of participation in other programs or cost effectiveness.
- Ancillary services and Emergency Curtailment options do not appear in the realistic achievable cases. These two options are excluded because both programs are typically operated quite differently and at different times than a typical peak-shaving program. Therefore, these estimates are always incremental to that potential.
- Estimates are at the generator. Potential estimates are presented in terms of savings at the generator and account for line losses.

Summary of Potential Results

Below, we present a summary of our results and point out some of our overarching observations.

Technical Achievable Potential

The analysis of individual DR options, which disregards cost-effectiveness and interactive effects, shows substantial savings from several options:

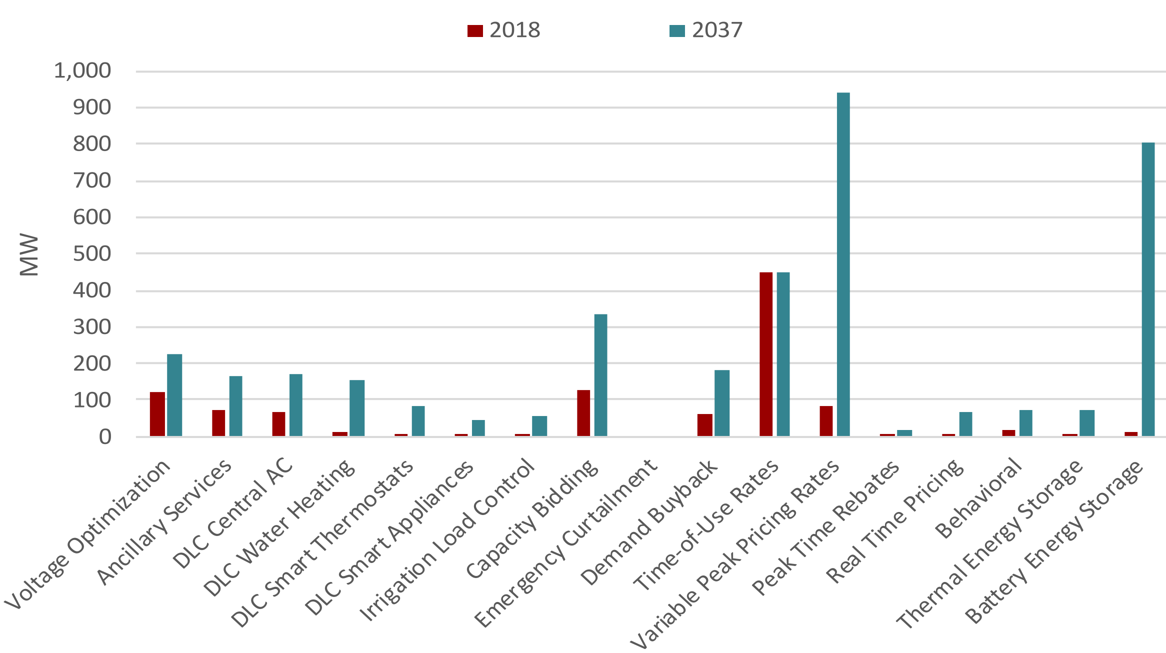
- In general, Battery Storage could be a game changer. We estimated a total potential of 806 MW in 2037 attributable to Battery Storage across the customer segments. Once batteries become cost effective, they could change the way customers use energy and how they respond to DR events.
- Variable Peak Pricing (VPP) is a significant driver of potential in all cases, and in the technical achievable case is the single largest program.

We present the result of the technical potential below in Table E-1 which presents the technical potential for each program in selected program years, and accompanying Figure E-1 which shows the potential by program in 2018 and 2037.

Table E-1 Technical Potential Results by Program Option (MW)

Program	2018	2019	2020	2023	2037
Voltage Optimization	122	130	137	170	226
Ancillary Services	71	92	134	167	168
DLC Central AC	67	116	185	175	169
DLC Water Heating	15	46	108	157	156
DLC Smart Thermostats	9	26	61	87	86
DLC Smart Appliances	5	14	33	47	47
Irrigation Load Control	6	16	38	55	58
Capacity Bidding	129	219	265	312	336
Emergency Curtailment	-	-	-	-	-
Demand Buyback	61	86	134	172	181
Time-of-Use Rates	448	441	432	409	447
Variable Peak Pricing Rates	81	244	571	838	942
Peak Time Rebates	2	6	13	19	19
Real Time Pricing	6	19	45	65	68
Behavioral	16	32	55	66	71
Thermal Energy Storage	7	21	50	72	75
Battery Energy Storage	15	46	76	216	806

Figure E-1 Technical Achievable Potential by Program Option in 2018 and 2037 (MW)



Realistic Achievable Potential

Below we present a comparison of the total estimated demand response potential for the two realistic achievable potential cases. In Table E-2 and accompanying Figure E-2 we show combined results across all programs. In Figure E-3, we show saving by program in 2037.

Some observations regarding the overall potential results include the following:

- Total DR potential is 2.2 GW in the high achievable case. The key elements that are driving this potential are:
  - Battery Storage is not cost effective and therefore not included in the low or high achievable cases.
  - As noted above, Ancillary Services and Emergency Curtailment are excluded from the low and high achievable cases.
- Total potential falls from 2.2 GW in the high achievable case to 1.3 GW in the low achievable case. The key elements driving this change are:
  - Overall reduction in participation rates across programs.
  - Moving from an opt-out / mandatory pricing scenario to a voluntary or opt-in pricing scenario.
- VPP is a significant driver of potential in all cases, and in the high achievable case is the single largest contributor to potential.
- Direct load control is heavily weighted toward DLC of CAC using switches. This is a result of the current deployment of switch based DLC programs in the state, and the utility's prediction that switches will continue to be the control method of choice in the future. However, the analysis has shown that this was not the only successful technology.

Some observations regarding the residential potential results include:

- The residential class is the largest contributor to potential in all cases and provides about 50% - 60% of the total load reduction depending on the case.
- Dynamic pricing rates are the key mechanism for achieving potential in the residential class.

Some observations regarding the commercial and industrial potential results include:

- Small and medium C&I are the smallest contributors to overall potential in all cases. This is driven by lower participation rates and smaller impacts for these customer segments. This is expected and is supported by the interviews with implementers and secondary research.
- Large and extra-large C&I are the second largest contributors to overall potential behind residential, jointly contributing about 25% of the total potential reduction in the achievable cases
  - The largest impacts in these groups come from Capacity Bidding and Demand Buyback with the rate-based options being smaller contributors.
- Irrigation and water pumping customers were included in the analysis, but the potential reductions from these customers are relatively small. Irrigation load control was not cost effective, and their impacts on rate based programs tend to be more conservative.

Table E-2 Overall Potential Results – Nominal and as a Percent of Baseline

Potential Case	2018	2019	2020	2023	2037
Potential Forecasts (MW)					
Realistic Achievable - High	849	1,179	1,706	2,017	2,214
Realistic Achievable - Low	265	520	991	1,255	1,339
Potential Savings (% of baseline)					
Realistic Achievable - High	3.8%	5.3%	7.7%	9.0%	9.7%
Realistic Achievable - Low	1.2%	2.3%	4.4%	5.6%	5.8%

Figure E-2 Overall Realistic Achievable Potential Results Compared to Baseline

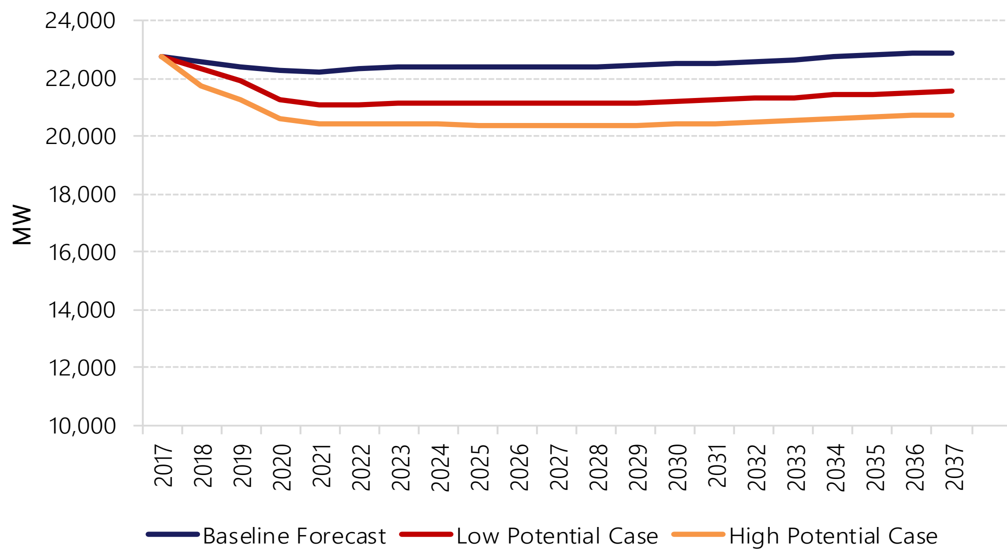
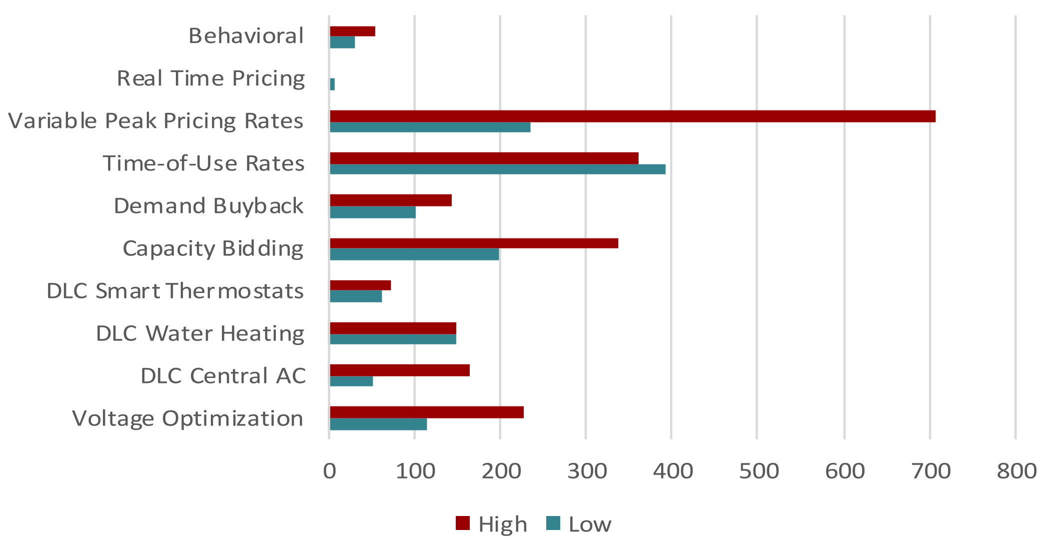


Figure E-3 Overall Potential in the High and Low Cases by Program in 2037 (MW)



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INTRODUCTION

On December 21, 2016, Michigan's new energy plan was signed into law. As part of this new legislation the Michigan Public Service Commission (MPSC) and Michigan Agency for Energy (MAE) were directed to engage in several new initiatives including a Statewide Assessment of Demand Response (DR) Potential. Demand response programs can reduce load on the electric grid during the highest times of usage (peak demand). The results of the potential study can be used to evaluate the utilities' progress in implementing their existing demand response programs and to serve as guidance for opportunities to expand their existing portfolios. In addition, this quantitative estimate of demand response potential will be used as an input for the state's integrated resource planning processes.

Public Act 341 directs the MPSC to conduct a statewide demand response potential study in the following terms. The Commission shall:

> *"Conduct an assessment for the use of demand response programs in this state, based on what is economically and technically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already been installed in this state and seek to fully maximize potential benefits to ratepayers in lowering utility bills."*

In accordance with this directive, the MPSC and the MAE engaged Applied Energy Group (AEG) and subcontractor DNV-GL to conduct a DR potential study for the State of Michigan. This study evaluates various categories of electricity DR resources in the residential, commercial, industrial, and agricultural sectors statewide for the years 2018-2037. The resource categories investigated include: direct load control, storage, demand side rates or incentive programs, curtailment agreements, voltage optimization, and ancillary services.

The key objectives of the study are to:

- Assess the annual technical, and achievable potential for reducing on-peak electricity usage through demand response programs for all customer classes for the 20-year period beginning in 2018.
- Develop a set of assumptions upon which potential estimates can be based such as customer eligibility, likely participation rates, per customer demand reduction, program costs, and avoided costs.
- Include estimates of potential for both traditional and non-traditional DR programs such as behavioral programs, direct load control programs, and voltage optimization (VO) programs at the distribution system level.
- Discuss barriers to achieve the identified potential and how they affect the recommended program designs.
- Include an assessment of how to fully maximize demand response potential using advanced metering infrastructure (AMI) already installed in Michigan.
- Incorporate the insights and conclusions gathered by the concurrent Market Assessment for large commercial and industrial customers conducted by Public Sector Consultants (PSC).
- Develop estimates or potential under two different scenarios.

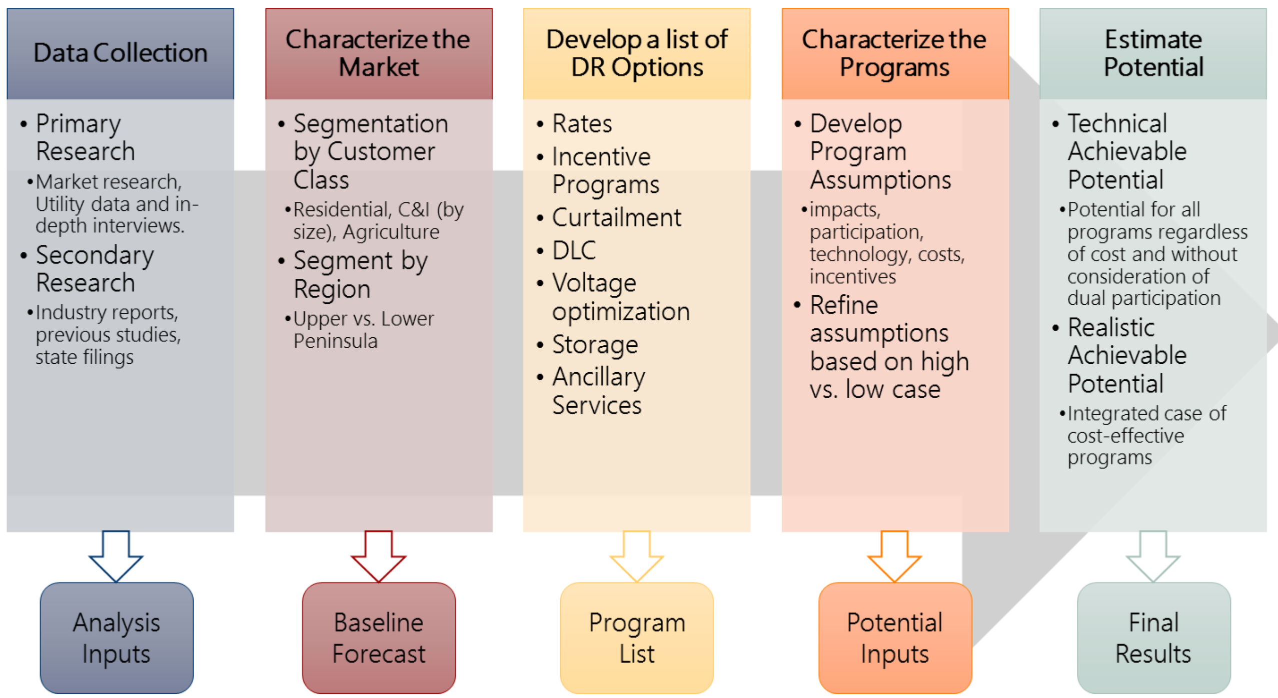
  - A low case, which represents a lower cost, lower participation scenario
  - A high case, which represents an aggressive roll-out of dynamic pricing coupled with higher incentives and higher participation.
- Finally, the study was designed to provide recommendations regarding potential for demand response in the future, and regarding potential future analysis enhancements.

In the subsections that follow, we provide a brief overview of the methods that we used to complete this study and information regarding the structure of the report.

Overview of AEG's Approach to the Study

In the figure below we present an overview of our approach to estimating DR potential in this study.

Figure 1-1 Overview of AEG's Approach to Estimating DR Potential



Each box in the figure above corresponds to a key step in the study. Each arrow points to a corresponding key study element which drives the analysis toward the final results. The steps and key elements are described in some additional detail below.

- Data collection for this study consisted of both primary and secondary research. The primary research included a residential customer survey to assess attitudes toward demand response programs and collect information on appliance saturations within homes. It also included in-depth interviews with both DR providers, and utility staff. Secondary research included reviewing reports, and past potential studies, filings, and other publicly available information. We also collected data from the utilities regarding their current load characteristics, programs, and customer base. The data collection process yields many of the key analysis inputs which allow us to characterize the DR programs included in the study and develop our baseline forecast.

- The market characterization is important because it frames the space in which the study will take place and defines the customer groups which the study will investigate. It establishes which customer classes will be included, and determines if there are any additional segments of interest. It incorporates the utility data provided during the data collection effort and develops a baseline forecast of demand by segment over the study horizon.
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- Next, we characterize each of the DR programs in our list, using the best available information to describe the program as it might be implemented and estimate program impacts, participation and costs. This step yields the inputs to the potential analysis that will result in estimates at each level of potential.
- Finally, we bring it all together to estimate the technical achievable, and realistic achievable potential for the set of programs we characterized across the entire state. The entire process was designed to meet each of the study's key objectives.

Structure of this Report

This report is organized into six chapters, plus three appendices.

- Chapter 2 – Market Research and Market Barriers
- Chapter 3 – Market Characterization and Baseline Forecast
- Chapter 4 – Program Characterization
- Chapter 5 – Demand Response Potential Analysis
- Chapter 6 – Conclusions and Recommendations
- Appendix A – Bibliography
- Appendix B – Survey Instruments
- Appendix C – Detailed Assumptions and Results

2

MARKET RESEARCH

Primary market research was conducted with residential customers to 1) develop equipment and technology saturations, 2) provide inputs for the potential study, 3) understand customer perceptions that might affect future participation and 4) estimate the likelihood that customers will participate in DR programs in the future.

In addition to the survey research with residential customers, in-depth interviews were conducted with DR providers and utility staff to get their perspectives on current DR program offerings, customer interest in DR programs and market barriers.

Concurrent with the development of the DR potential study, the MPSC enlisted Public Sector Consultants (PSC), in partnership with Navigant Consulting (Navigant), to conduct a market assessment with large commercial and industrial businesses in Michigan with demand for energy greater than 1 MW to determine awareness of and interest in DR programs. The PSC team conducted a survey and in-depth interviews to assess preferred program characteristics, saturations of enabling technologies including energy management systems, storage, and on-site generation, and willingness and ability to participate in DR programs.

Residential Survey

A total of 405 residential surveys were completed with customers in Michigan. Online survey panels were used to source a sample of qualifying Michigan households. Qualifying respondents were screened to ensure that they were:

- Over 18 years of age
- Responsible for making electricity-related decisions
- Had their primary residence in Michigan
- Did not work for an electric or gas utility

The final survey dataset was weighted by age and income in order to ensure that it reflected the overall Michigan population on key demographics. A copy of the survey instrument can be found in Appendix B.

Appliance Saturation Results

Typical Michigan residential home and head of household characteristics are illustrated in Figure 2-1. Most Michigan homes are less than 2,500 square feet (73%) and have on average 2.9 persons per household, although almost a quarter are single-person households. Eighty percent (80%) of households are single-family and 20% are multi-family.

Forty-two percent (42%) of heads of household are between 25 and 44 years old, while 18% are 65 or older. Forty-four percent (44%) are employed full time and 21% are retired.

Figure 2-1 Typical Home and Head of Household Characteristics

Typical households also have the following energy-related characteristics:

- Central air conditioning (68%)
- Natural gas heating (66%)
- Natural gas water heating (63%)
- Very few hot tubs or swimming pools (only 5% have hot tubs and 8% have swimming pools).

Customer Perceptions

Survey respondents were asked about their perceptions of their utility providers and their attitudes regarding energy use. These attitudinal questions were asked using a 10-point scale, with a “1” meaning the lowest rated option (e.g., strongly disagree, extremely dissatisfied, etc.) and a “10” meaning the highest rated option (e.g. strongly agree, extremely satisfied, etc.).

The analysis below aggregates the survey responses on these questions into three groups:

- “Top 3 Box” responses represent the total proportion of respondents who provided a rating of 8, 9, or 10 to the question
- “Middle 4 Box” responses capture those who provided a rating of 4-7
- “Bottom 3 Box” responses capture those who provided a rating of 1, 2, or 3.

Figure 2-2 and Figure 2-3 on the following page, present customer perceptions of their electric utility provider, and their attitudes regarding energy use, respectively.

Customer perceptions of their electric providers, below, are generally positive with the majority giving their electric utility a top 3 box rating on overall satisfaction, promoting programs that save customers money, and being a credible source on energy efficiency.

Figure 2-2 Overall Perceptions of Electric Utility Provider

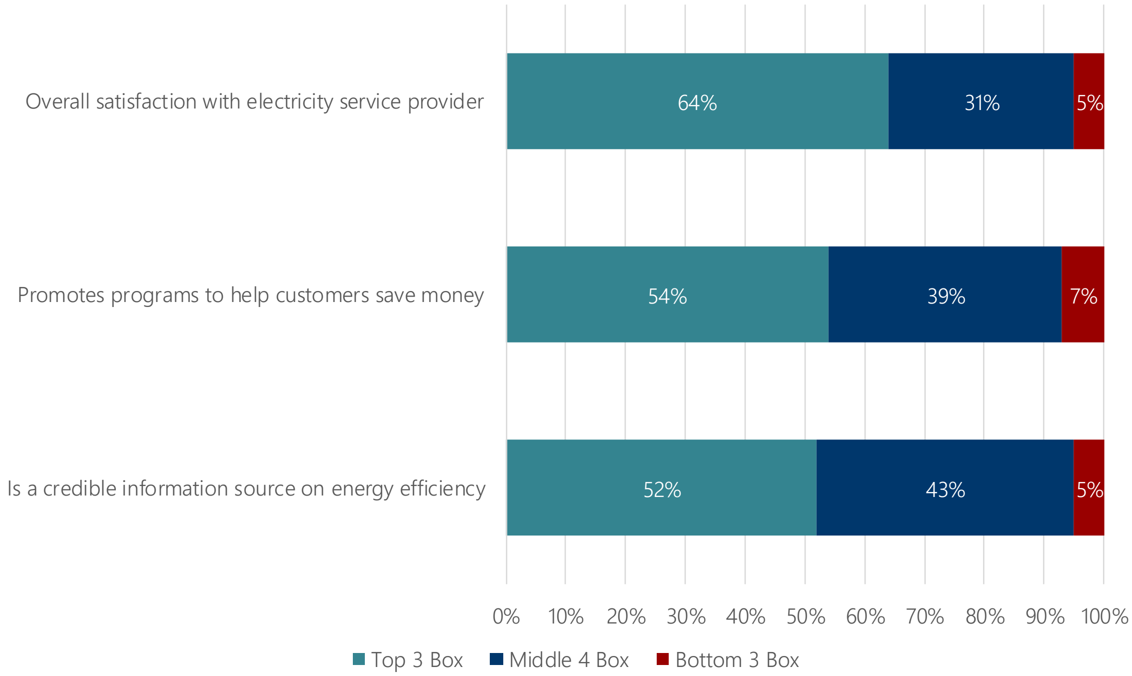
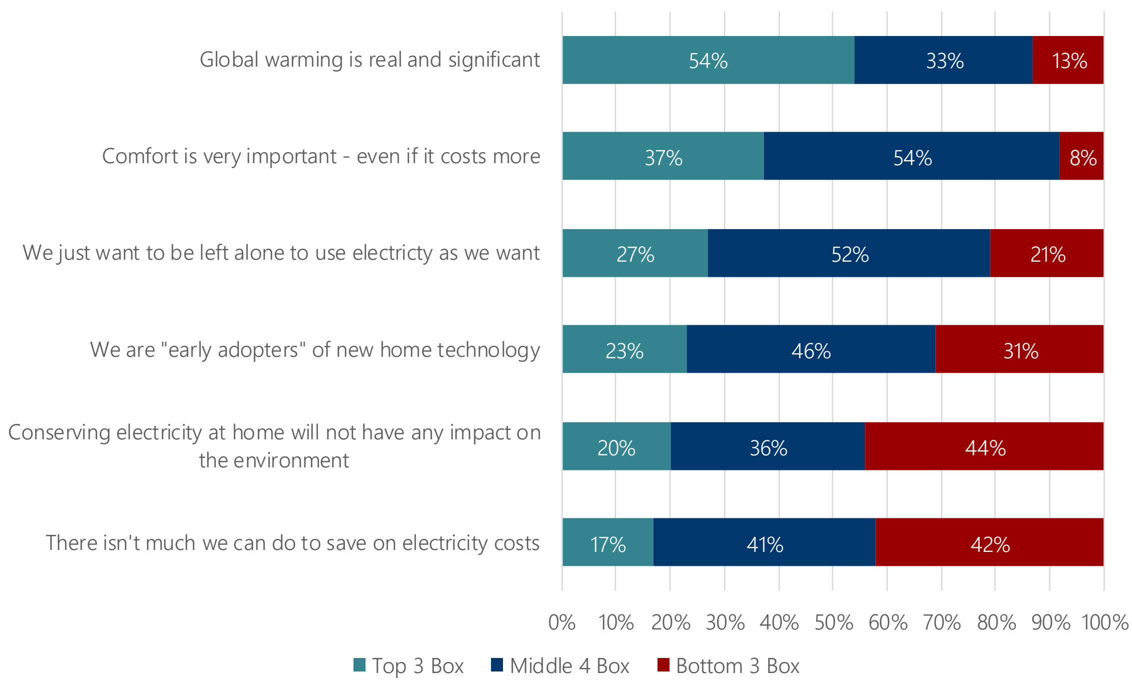


Figure 2-3 Perceptions Regarding Energy Use and Conservation



Michigan customers' attitudes toward energy use and conservation, above, lean towards personal responsibility and "green". The majority agree with the statement that climate change is real and significant, and a large percentage disagrees with the statement "there isn't much we can do to save on electric costs" (42% bottom 3 box). Most customers also and disagree with the idea that conserving electricity at home will not have any impact on the environment (44% bottom 3 box). It's important to note that these attitudes are not particularly strong given that a third to more than half of respondents gave middle box ratings on each of these attitudinal questions.

Customer End-use Equipment

We also asked customers about the types of equipment that they have in their homes including questions about heating and cooling equipment, and other appliances that could be targeted for demand response. The key goal of these questions is to develop reasonable equipment saturations for the potential study.

Figure 2-4 Cooling Equipment Saturation

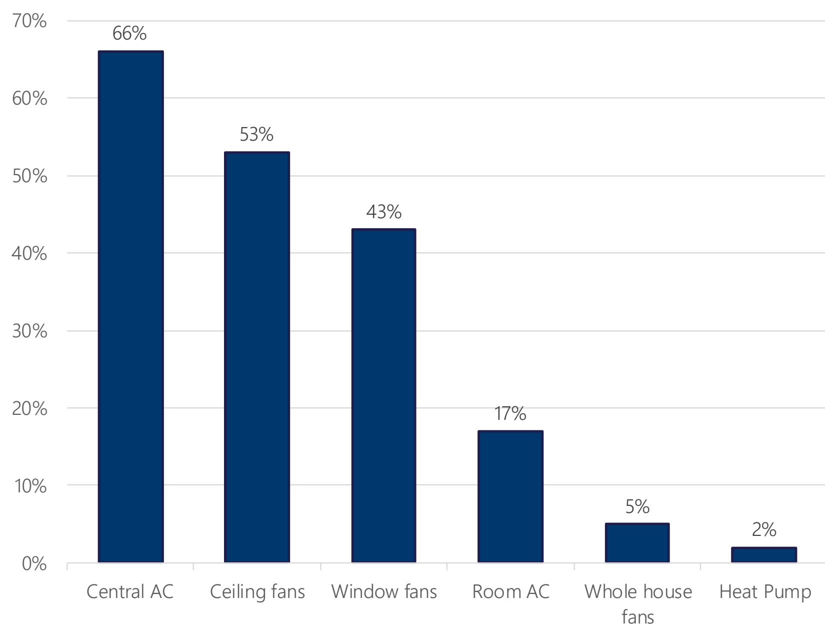


Figure 2-4 illustrates the penetration of central air conditioning, and other home cooling equipment such as fans, and room AC. It is important to note that customers could indicate that they had more than one appliance, i.e., central AC and window fans, so the percentages in the graph add up to more than 100%.

Two-thirds of households in Michigan have central air conditioning, more than half have ceiling fans, and 17% have room air conditioning.

Figure 2-5 Heating Equipment Saturation

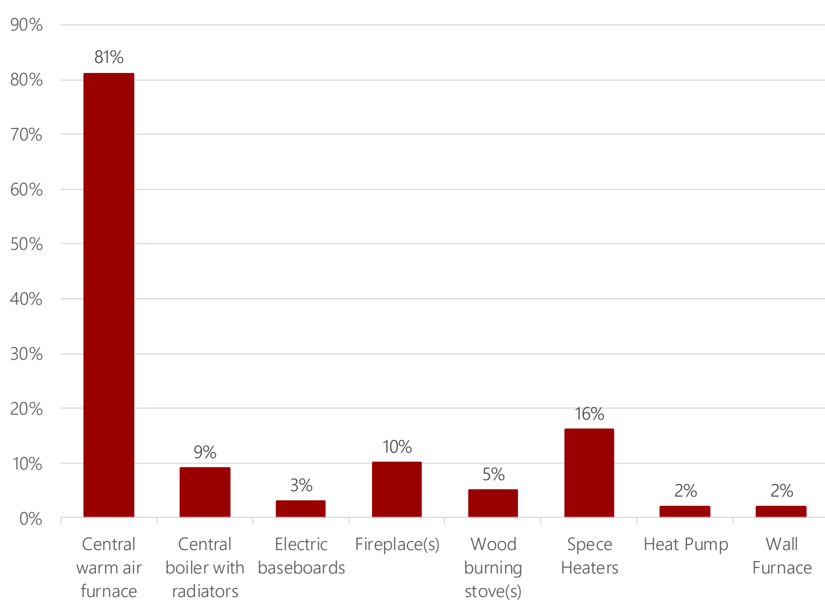
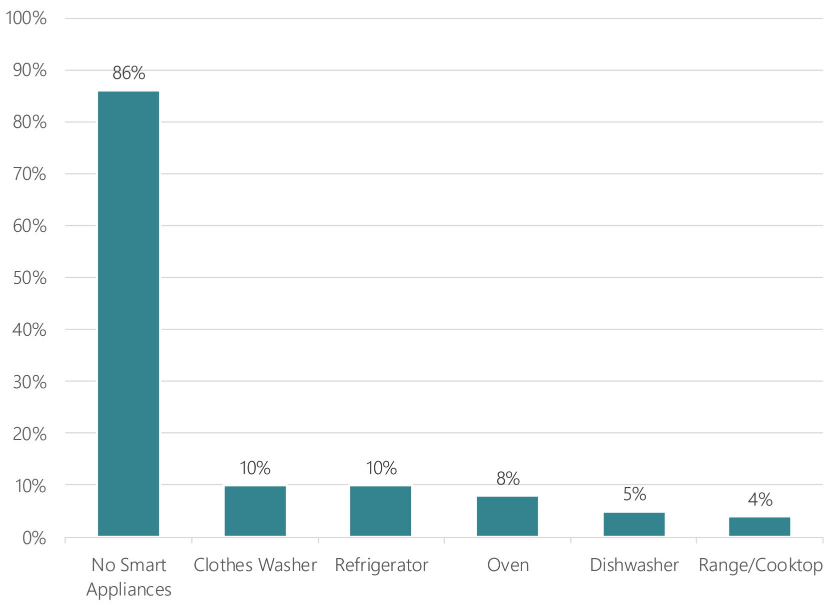


Figure 2-5 illustrates the penetrations of various types of heating equipment within customer homes. Central warm air furnaces are the most prevalent with 81% of households reporting having this type of heating system. Smaller percentages of customers have space heaters, fireplaces and central boilers, while very few households have electric baseboard heating, heat pumps or wall furnaces.

Figure 2-6 Smart Appliance Saturation



Because this is a DR potential study, we also estimated the saturation of smart appliances that could help residential customers respond to price fluctuations or DR events. Smart appliances were defined as "appliances that are connected to your smartphone, tablet or computer to give you information and control of the appliance". The results are presented in Figure 2-6. Overall, few customers reported having smart appliances. With only about 10% reporting either a smart refrigerator or clothes washer in their home.

New electric technologies are also uncommon, with only 2% of customers having solar and only 3% having electric vehicles.[1]

Program Interest Results

The residential survey was also used to assess customers' stated interest in participating in demand response programs. We then translated that interest into estimates of the proportion of customers who would actually adopt these programs, given the opportunity to do so and given that they have the qualifying technology. We looked at two different types of programs, time-based rates and direct load control.

Customer Stated Interest in Time-based Rates

Customers were introduced to three pricing options: a time-of-use rate (TOU), a real-time pricing rate (RTP), and a peak day pricing (PDP) rate. The rates were presented on their own and with 12 months' bill protection. Each rate was presented to the respondents as follows:

- TOU - First, consider an electricity rate in which the price for electricity more closely connects to the price of producing that electricity. With such a rate, electricity consumed during "off-peak" hours in the early mornings, evenings, nights and weekends would be cheaper than today, while electricity consumed during "on-peak" hours in the late morning and afternoon weekday hours (when the most electricity is consumed) would be more expensive than it is today. You could lower your monthly electric bill by as much as 5-10% by moving electricity use to off-peak hours or by reducing your use during on-peak hours.
- RTP - Now, consider an electricity rate in which electricity prices would vary for each hour of every day, depending on how much it costs to produce electricity during that hour. While electricity prices could differ every hour under this rate, it would still be true that electricity prices would tend to be

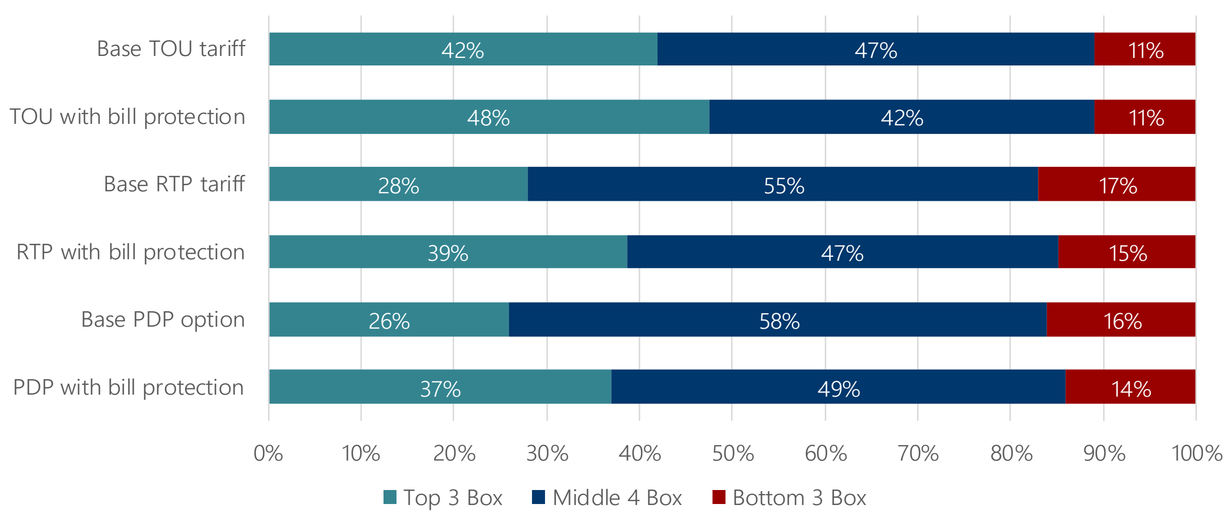
[1] A three percent penetration of electric vehicles may be on the high side, we find that customers sometimes confuse plug in hybrid vehicles with electric vehicles.

higher during times of "peak" demand, such as during weekday, summer afternoons, and lowest during times of "off-peak" demand (nights and weekends). With this rate, you could potentially save as much as 5-10% by moving electricity use to times when electricity prices are lower, or reducing usage during times when electricity prices are highest

- PDP - Now consider another electricity rate in which electricity prices would be lower than they are today for all hours of the day and the year except for the hottest 10-12 days of the summer. For the hottest 10-12 days of the summer electricity prices would be much higher than they are today. You could potentially lower your electric bill by as much as 5-10% by reducing or moving electricity use just during these 10-12 days each year.

Figure 2-7 below, presents the respondent's stated interest in each of the three demand-side rate options. Customers most preferred the TOU options, with 42% rating their interest in the base TOU program at top 3 box. Interest in the RTP and PDP options is approximately fifteen points lower than interest in the TOU rates. All rate programs received higher ratings (6 – 11 points) when coupled with 12 months' bill protection.

Figure 2-7 Stated Interest in Time Dependent Rate Options



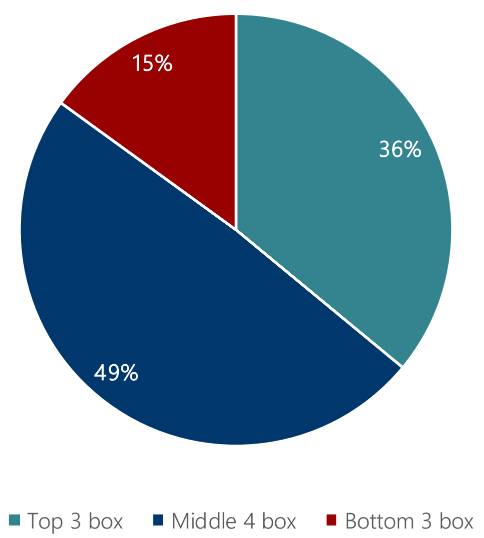
Customer Stated Interest in Direct Load Control

Customers were also asked about their interest in participating in a direct load control (DLC) program with three different annual incentive levels, $25, $50, and $100. The DLC program was defined for customers as follows:

- DLC - Some utilities offer programs that are designed to help the utility meet customer demand for electricity during summer weekday afternoons when consumption of electricity is the highest. Participating customers help to increase the reliability of their electric service by allowing their usage to be managed during these times. Customers in these types of programs are often eligible to receive an incentive, depending on the number of times their usage is managed.

  One way that other utilities manage customer demand is to install a device on air conditioners that allows them to cycle the compressor on and off for 30 minutes out of every hour. These periods usually happen on hot summer weekday afternoons, for no more than 10 days each summer. There may also be other appliances (pool pumps, dehumidifiers, etc.) which the customer might allow the utility to control.

Figure 2-8 Stated Interest in the Base DLC Program with $50 Incentive



In Figure 2-8, left, we present customers' stated interest in participating in a DLC program with a $50 annual incentive. Just over one-third (36%) of respondents give Top 3 box ratings to the DLC program option at that incentive level. It is important to note that lowering the incentive reduces interest significantly. Only 32% of those who rated their interest as a "7" or higher on the scale, give top 3 box ratings when the incentive is reduced to $25. Increasing the incentive, however, does not substantially increase program interest. Just 8% of those with little interest in the program at $50 (those who rated their interest as "6" or lower) give top 3 box ratings when the incentive is increased to $100.

During the survey, we also asked customers to rate their interest in a traditional DLC program vs. a Smart Thermostat program. The Smart Thermostat program was described as follows:

- Smart Tstat DLC- Another way that these energy management programs might work is that you could allow your utility to communicate directly with a Smart Thermostat in your home (either one you already have or one that would be installed by the utility). Under this sort of arrangement, the utility would send signals to your thermostat which would adjust the settings on your thermostat during peak usage times in the summer to a few degrees higher.

  The advantage to this type of program is that it would mean not having to add a control device on your air conditioner, and you could agree with your electric utility ahead of time about how your thermostat settings would be adjusted during peak periods.

Figure 2-9 Stated Interest in the Smart Thermostat DLC Compared to Base DLC Program

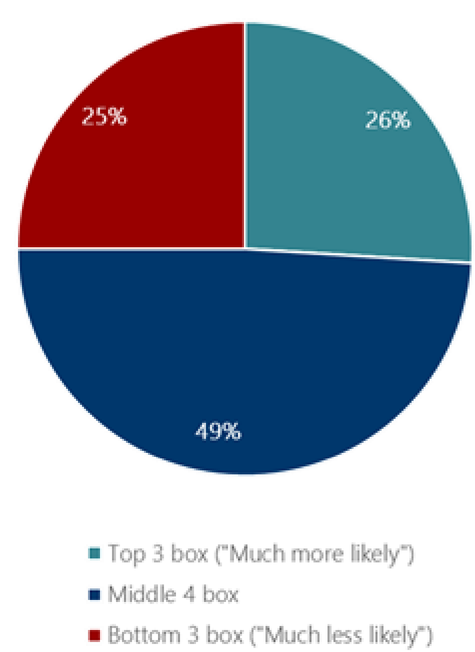


Figure 2-9 right, shows that interest in a smart thermostat version of the DLC program is similar to interest in the standard DLC program. Twenty-six (26%) percent of respondents give ratings indicating that they are "much more likely" to participate in a smart thermostat version of the DLC program compared to their interest in the base DLC program, while 25% say they are "much less likely" to participate in the smart thermostat version. Half of customers (49%) say their interest in the two programs is approximately equal.

Likelihood to Adopt

The results reported so far represent what is called "stated intent." Stated intent represents what customers tell us about their interest in participating (or likelihood to participate) in each program. However, copious research and real-world experience also tell us that stated intent does not translate in a simple way into likely downstream behavior. This happens because customers tend to have what is called an "optimism bias," and consistently overstate their actual likelihood of taking any future action. As a result, we know that we need to apply a correction to the results reported here to generate more accurate estimates of future behavior.

This process of correcting for overstatements of likely behavior is described as making a "say/do" correction because it accounts for the fact that customers overstate the likelihood that they will do something.

Responses to the core program interest questions were first analyzed by "taking customers at their word," and assuming that their "1" to "10" responses can be stated as simple percentages representing their probability of adopting the tested measure. So, if a customer rated their likelihood to take a given action as a "9," then they were calculated as being 90% likely to take that action. The results of these calculations are called "unadjusted" take rates because they "take customers at their word."

"Unadjusted" take rates for the tested programs are outlined in Table 2-1 below. These values are "unadjusted" because they translate customer responses into an aggregate percentage likelihood-to-participate in a given program if they were able to do so.

Table 2-1 Unadjusted Take Rates for Tested Programs

Programs	Unadjusted Take Rate
Base TOU Tariff	67%
TOU Rate w/Bill Protection	70%
Base RTP Tariff	61%
RTP Rate w/Bill Protection	64%
Base PDP Tariff	59%
PDP Rate w/Bill Protection	63%
DLC at $25	52%
DLC at $50	63%
DLC at $100	70%

The method used to determine the say / do adjustment in this project was to leverage information collected in other states that made it possible – in those jurisdictions - to link stated likelihood to adopt responses to actual program participation levels using "anchor" survey questions:

- Specifically, survey respondents in other states (Missouri, Illinois, Colorado) were presented with a description of an EE / DR program which was described as closely as possible to an existing EE / DR program and asked how likely they would be to participate in that (existing) program.
- Since historical program participation levels were available for the actual program, customer statements about their likelihood to participate in the "hypothesized" program

(which is effectively the real program) could be compared directly to those historical participation levels.

- Comparing customer claims about how likely they would be to participate in a "hypothetical" program with their actual participation in an equivalent program provided a "say/do" adjustment grounded in real-life experience.
- Note that this methodology could not be implemented in the current engagement because of the lack of current programs against which to compare participation.

Using the methodology just outlined, if, for example, the unadjusted adoption rate for a given program was 66% and the "actual" program participation rate was 33%, then the say/do correction factor was defined as 50% (or 66% divided by 33%). The AEG Consulting team has found say/do correction factors ranging from 40% to 60% across different jurisdictions in the Midwest. Given the fact that DR programs will be new to residential customers in Michigan, AEG believes that it is safest to assume that customers may not have a clear understanding of how the programs would work or what the impact of the programs might be, and as a result, using a more conservative correction factor (45%) would be appropriate.

Once the say/do correction values are applied, the resulting values represent AEG's best estimates of realistic achievable potential for each program (in terms of the proportion of customers signing up for the program). And note that this analysis also assumes that customers must make an active decision to participate in the programs (defaulting customers onto a rate would obviously have different outcomes).

Table 2-2 Applying the Say/Do Correction

Programs	Unadjusted Take Rate	Adjusted – Realistic Adoption Rates
Base TOU Tariff	67%	30%
TOU Rate w/Bill Protection	70%	32%
Base RTP Tariff	61%	27%
RTP Rate w/Bill Protection	64%	29%
Base PDP Tariff	59%	27%
PDP Rate w/Bill Protection	63%	28%
DLC at $25	52%	23%
DLC at $50	63%	28%
DLC at $100	70%	32%

Customers were also asked about their interest in participating in a DLC program which would leverage a (potentially new) Smart thermostat. Interest in this program was assessed by comparing interest in this option to the baseline DLC program (at a $50 incentive level):

- Customers were asked if they were "more likely" or "less likely" to participate in the Smart Thermostat version of the program compared to the baseline DLC program.
- Since customers were approximately evenly split in their response to the Smart Thermostat version of the program (26% "much more likely" to participate and 25% "much less likely), the AEG team has assumed that take rate calculations developed for the base DLC program can also be applied to the Smart Thermostat program.

In-depth Interviews

In-depth interviews were conducted with five DR providers and staff from three utility companies in Michigan. The interviews with the DR providers focused mainly on the market for DR programs in the small and medium business customer segment, while the utility interviews focused on their current and planned offerings. A copy of the in-depth interview guides can be found in Appendix B. We also include below, insights from PSC's interviews with extra-large C&I customers in the state of Michigan.

Key Insights – DR Providers

- The main driver of program interest is cutting costs and saving energy. There is also a growing group of customers that is environmentally motivated.
- Technology is an extremely important component of DR programs that appeals particularly to the small and medium business (SMB) customers.
    - Most SMB customers do not have automation technology, but there is growing interest in smart thermostats.
    - Some medium businesses, particularly chain stores, currently have energy management systems (EMS), which support DR implementation.
    - A platform that has accurate information on customer response can help keep customers engaged in DR, and help them learn how to shed load.
    - Customers are receptive to utility control of automation, as long as it does not disrupt their core business.
- DR combined with EE, and/or programs that combine electric, gas and water savings are the most attractive to the SMB market because they provide customers with the greatest potential to save money.
- In person meetings and conversations with the decision maker are the most effective marketing strategy for this sector.

Key Insights Utility Staff Interviews

- Two of the three utilities interviewed currently offer DR programs. These include Residential DLC programs (including Smart Thermostat programs) dynamic rates, and C&I emergency dispatch programs, often referred to as legacy interruptible programs.
- Utilities believe opt-in rates are more attractive and will be more successful than opt-out rate programs.
- Utilities also believe that customers do not want to be in the energy management business, so simplicity is key to a successful program design.
- Automation is important to DR and will likely grow but will grow slowly – particularly in the C&I market.
    - Buildings are older and hard to retrofit with automation. It isn't until C&I customers build new buildings or renovate that they seriously look into automation.
    - For all sectors, DR won't drive the adoption of automation, but customers interested in automation will be more interested and likely to participate in DR.
- Utilities currently do not have a huge need for DR. Many of their existing programs that are event driven are called rarely.

Key Insights Extra-Large Commercial & Industrial Customers

- Customers that are highly energy intensive (measured as the percent of variable costs made up by energy, and in particular, electricity costs) with high process flexibility approach demand response programs in a fundamentally different way than the other customer segments.
  - They invest in staff and equipment to manage their energy costs and in some case, adopt key performance indicates to measure their efforts to manage energy costs.
  - Given their deep understanding of energy markets, they seek compensation for their load reductions that reflects the system savings they generate.
  - Load management capabilities of these customers extend beyond system emergencies and summer peaks; they are able to shift load based on market conditions and availability of resources.
- Customers that are less energy intensive, but have the ability to curtail load because of the nature of their operations or availability of enabling technology, are interested in demand response options that allow them to make real-time decisions to participate or not.
- Extra-large C&I customers are not interested in relinquishing control to a utility or third-party to reduce load during a demand response event; they prefer to implement load reductions themselves to minimize impact on production and ensure employee safety.
  - Some customers have the ability to respond very quickly to a curtailment request (10 minutes or less) because of large, discreet loads or availability of on-site generation.
  - Most customers required a minimum of one to two hours to curtail load.
- Extra-large C&I customers see potential synergies between demand response and energy efficiency and see both as contributing to their organizational sustainability goals.

Market Barriers

The following barriers to DR programs for residential customers were identified through secondary research:

- Lack of education – One of the most significant barriers affecting residential customers is a lack of understanding about the purpose and structure of demand response programs. Many customers do not understand their own energy use, so communicating the problem of peak demand constraints can often be a complicated and confusing topic for customers.[2]
- Customer acceptance – A customer's willingness to accept any perceived risk from participating in DR programs can be barrier, whether that be any financial burden or invasion of privacy.[3]
- Benefit realization – If benefit streams are confusing or inconsistent, customer acceptance, participation, and persistence can be impacted.[4]

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[2] Szablya,Louis. Electric Power and Light. "Breaking Down Barriers to Residential Demand Response", October 1, 2012. Website.
[3] CAISO Demand Response Barriers Study, 2009. https://www.caiso.com/Documents/DemandResponseBarriersStudy-AppendixC.pdf
[4] Weck, atl. Review of barriers to the introduction of residential demand response: a case study in the Netherlands. International Journal of Energy Research. Volume 41. Issue 6. http://onlinelibrary.wiley.com/doi/10.1002/er.3683/pdf

- Privacy – With advances in technology, customers may be wary about increased utility presence in their home and with the usage.[5]
- Customer persistence – Keeping customers positively engaged and enrolled in the programs is a significant challenge that can turn into a barrier.
- Technology infrastructure – Having sufficient technology deployment (using switches, thermostats, AMI meters) and/or adoption that is cost effective for the utility is essential for specific programs to establish performance and compensation.[6]

The following barriers to DR programs for small and medium business customers were identified in the in-depth interviews:

- Program complexity – Programs that are hard to understand, particularly how the program will affect a customer's business operations, will be a harder sell for customers.
- Small incentives – Incentives that are perceived as too small will make the effort required not worth it for customers. For programs where small incentives are likely, this can be overcome by coupling DR programs with EE options.
- Hassle factor – Similar to small incentives and program complexity, if the customers perceive the program to be too much of a hassle for too little benefit they will not participate.
- Lack of education – Many customers do not know how to shed load without negatively impacting their business. As noted in the utility interviews, customers do not want to be in the energy management business, and therefore need easy ways to shed load to comply with the program and achieve benefits. Technology can help overcome this barrier, both with enabling technology (such as smart thermostats, controls and switches) and platforms that let customers see data on how they responded after events. On-site DR audits can also be performed to educate customers on their load-shedding options.
- Regulatory hurdles – Regulators have encouraged utilities to try innovative programs but are not always willing to wait long enough to see if the programs are successful. Introducing new programs and concepts to customers takes time, and initially there can be a long sales cycle to get enough customers to participate. Regulators and utilities need to be willing to invest the amount of time and effort that is required to try new programs and understand they may not see immediate results.

Programs need to be simple, consistent, and provide clear benefit to customers in order to overcome barriers for residential and small/medium C&I customers.[7]

PSC Research

PSC and Navigant conducted surveys and in-depth interviews with business entities with loads over 1 megawatt (MW). These large business customers include manufacturing establishments, large educational and health care institutions, shopping malls and entertainment venues, municipal governments, property management companies, and other recognizable entities throughout the state.

[5] 2012 Assessment of Demand Response and Advanced Metering. Federal Energy Regulatory Commission, page 49. https://www.ferc.gov/legal/staff-reports/12-20-12-demand-response.pdf

[6] Demand Response as a Power System Resource Program Designs, Performance, and Lessons Learned in the United States. Regulatory Assistance Project. http://www.raponline.org/wp-content/uploads/2016/05/synapse-hurley-demandresponseasapowersystemresource-2013-may-31.pdf

[7] CAISO Demand Response Barriers Study, 2009. https://www.caiso.com/Documents/DemandResponseBarriersStudy-AppendixC.pdf

The purpose of this market assessment was two-fold: 1) to inform key inputs to the Demand Response Potential Assessment related to extra-large commercial and industrial entities and 2) to provide important insights that will help guide development of policies and programs to encourage participation by large commercial and industrial (LCI) businesses in programs that support the efficient operation of Michigan's electric system.

Through the survey and interviews, the research team found that over half of these LCI businesses would be willing and able to participate in DR programs and depending on the program design, most would be able to reduce load by five to thirty-five percent during periods of peak demand on the electric system. Some energy intensive customers with flexible processes may be able to reduce load by as much as two-thirds of peak facility load.

The research team worked with the utilities, the Michigan Agency for Energy, and the MPSC to gather contact information and to conduct outreach to LCI energy users to encourage participation in the market assessment. In all, 52 surveys and fourteen in-depth interviews were conducted with organizations representing key segments in Michigan. The surveys and interviews covered topics including:

- Characteristics of LCI operations in Michigan
- Awareness of and experience participating in DR programs
- Preference for different program design features and the impact on ability to curtail load during peak periods
- Adoption of technologies that could enable participation in demand response programs including energy management systems, storage, and on-site generation

PSC reviewed the inputs to the Demand Response Potential Study and compared them to input from large commercial and industrial customers through a survey and interviews. To the extent possible, we tried to obtain quantitative estimates of the amount of load that customers would be able and willing to curtail under different program scenarios. However, given the wide variation in characteristics and challenges in getting businesses to assess their likely behavior under different hypotheticals, the does not support precise estimates of potential participation rates or load reductions. However, it provides useful insights from customers about their program participation decision making that help to confirm or adjust program assumptions and identify program attributes that may encourage expanded participation. Table 2-3 summarizes the key inputs to the potential study informed by the market assessment.

Table 2-3 Inputs Informed by the MPSC Demand Response Market Assessment

Program Name	Rationale for Difference
Emergency Curtailment	• PSC estimates a higher dropout rate because a number of large customers expressed interest in other programs that promised greater opportunity for participation, and could potentially migrate if these programs were available • Based on the input of interviewees and relative to incentive requirements for other programs, we recommend incentives of $15/kW-year for the low case and $20/kW-year for the high case
Curtailment Agreement	• PSC estimates a higher potential for participation based on the significant interest expressed by respondents; since these respondents also represent a higher percentage of load (40% of load compared to 25% of customers), PSC estimates that the peak reduction as a percentage of load could also be higher • In the base case, the percent of load reduction ranged from 5 to 25% – larger companies tended to indicate larger load reductions, so PSC recommends a base case load reduction above the midpoint of the range • In the high case, the potential load reduction was 35% in total or a 50% increase over the base case, so PSC recommends a 30% of load reduction in this case • In the interviews, some customers suggested $30-35/kW-year as a threshold level for encouraging participation, but that $50/kW-year would be a target incentive level
Demand Buyback/Energy Exchange	• Customers expressed interest in the program based on its flexibility, with particularly strong interest among high load customers, which leads PSC to recommend higher participation rates and potential % load reduction • There was some sensitivity to length of demand response, which leads to a lower PSC estimate • As a relatively new program to customers, there will need to be time allotted to ramp up to full participation potential
Time-Of-Use (TOU)	• PSC recommends a downward adjustment to high participation case to allow for customer migration to other time differentiated rate programs (Variable or Critical Peak Pricing and Real Time Pricing)
Variable Critical Peak Pricing (CPP)	• PSC recommended lower participation given limited expressed capacity on the part of customers to participate in the program, and because those with capacity expressed interest in real-time pricing
Real-Time Pricing	• PSC recommended higher participation rate for the high case. Sophisticated, heavy users expressed strong interest in the ability to participate in real-time pricing in order to maximize their cost savings and revenue opportunities.

3

MARKET CHARACTERIZATION

The first step in a market potential study is to create a market characterization. The market characterization creates a snapshot in time for each of the segments and records how many customers there are, what their peak demand was in the base year, and what programs customers are involved in. The process begins by gathering data from utilities, third party aggregators, and secondary sources to create a complete picture. Once all the data is gathered, the market profile is created which establishes the high level, base year values for the model. Finally, once the base year values are assembled, a baseline forecast is created that extends to the end of study period. The baseline forecast is critical to study as it is the key determinant for customer growth, measuring potential peak reductions, and the economic feasibility of programs based off avoided cost projections.

The key elements of the market characterization are described in the following subsections and include:

- Data collection
- Customer segmentation
- The development of the baseline forecast

Data Collection

The purpose of the data collection was to collect detailed information on DR programs, avoided costs, customer distributions, and demand forecasts. In July and August 2017, AEG sent data requests to load serving entities throughout the state. AEG provided a template data request that was pre-populated with data from third party sources and solicited the utilities to provide updated or more accurate information. Specifically, the data request included:

- Corporate discount and administrative rates
- Sector and segment level base year and forecasted peak demand levels for summer and winter
- Sector and segment level customer counts
- Avoided energy and capacity costs for the base year and forecasted years
- Economic data such as household square footage, heating and cooling degree days, and disposable income
- End use equipment saturations such as cooling, electric space heating, and electric water heating
- Program level information such as programs offered, development and administrative costs, evaluated savings, and performance metrics

Working with the MPSC Staff, we identified six utilities to target based off their size and location within the state. AEG requested that all data be returned to us no later than August 11th, 2017. Overall utility response was good with only one utility not providing data and one requiring a non-disclosure agreement for utility level data which AEG agreed to and signed.

Secondary Sources

While most utilities responded to the data request, there were still gaps in the data coverage that had to be filled. For example, while AEG received responses for the majority of Michigan's peak demand, not every utility could be reached. This required us to 'true up' the utility-provided data to the system peak total for the state. Likewise, due to how programs are represented in the model, the sector level customer data had to be broken down further into various segments that represented customers of a certain load size as those customers would be offered different programs in the model and would provide varying levels of peak reduction once enrolled. In these cases, AEG relied on secondary data sources such as EIA utility data and forecasts, other demand response potential studies, and expert opinion to finalize the market characterization.

We built the market characterization up from the least preferred source to the most preferred, saving the utility provided data for last as it is the most accurate. This ensured that we had coverage for every variable required in the model and that the most reliable source was always used. Together, the primary and secondary sources provided a cohesive market snapshot and established the baseline forecast for the period covering 2016-2037. Finally, once the market characterization was complete, calls were held with the utilities to ensure that the data and assumptions in the characterization were fair and representative of the state.

Customer Segmentation

Due to the varied nature of the programs being offered in the model, each of the sectors were broken down and grouped into various segments based on their load profile. Specifically, the commercial and industrial sectors were combined and then broken into five distinct segments:

- Residential
- Small Commercial and Industrial (≤30 kW)
- Medium Commercial and Industrial (≤200 kW)
- Large Commercial and Industrial (≤1,000 kW)
- Extra-Large Commercial and Industrial (>1,000 kW)
- Irrigation & Water Pumping

This segmentation was done to better capture how each program would impact different customer classes. For example, curtailment agreements are typically only offered to customers of a certain size that would have the capacity and internal support structure to be able to respond effectively to curtailment events.

AEG relied on secondary sources to break the sector totals provided by the utilities down to each segment. Representative load profiles from other studies were utilized to estimate the proportion of each segment to the summer and winter peak demands across both peninsulas. In addition, customers were allocated into each segment and then cross verified using per customer peaks to ensure that the results were reasonable.

Baseline Forecast

Once energy use in the base year is determined, the next step is to develop a baseline forecast from 2016 through 2037. AEG developed its forecast using historical EIA-861 data, internal utility forecasts, and third-party sources to extend the market characterization snapshot into a baseline forecast by projecting a number of potential drivers:

- Existing customer counts and new construction forecasts
- Load forecasts from the utilities

- Avoided energy and capacity costs
- Pre-existing Demand Response programs implemented by the utilities
- Econometric elasticities in demand and consumption

Within the model, this forecast is used as the measuring stick for all potential – any program that is run is subtracted from the baseline forecast of demand and the forecast of avoided energy and capacity costs determines what programs are cost effective and viable.

Customer Forecast

The first forecast that AEG reconciled with utility forecasts and EIA data was the customer forecast by segment which are shown in Figure 3-1 and Figure 3-2 (and Table 3-1) and Figure 3-4 and Figure 3-4 (and Table 3-2). Because the residential customers accounts for such a large percentage of the overall population in each region, we present the breakout for the C&I customers only in Figure 3-2 and Figure 3-4.

The customer forecast was largely derived from EIA-861 data which provided for a historical count of meters across the state. The responding utilities provided individual forecasts that were used to forecast the growth rate from 2016-2037. The result of this was an increase in population of 7.2% for Residential and 7.8% for Commercial and Industrial segments. Using the customer growth forecast then allowed us to estimate the kW per customer in each segment which allowed us to begin breaking down the demand forecast for the state.

Figure 3-1 Customer Forecast for Lower Michigan

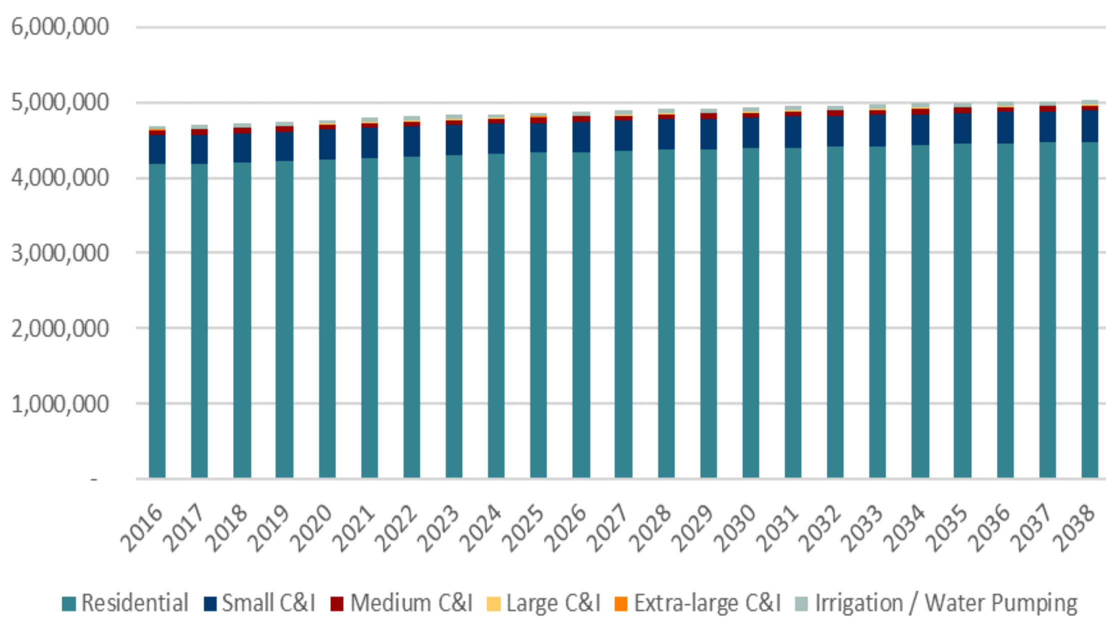


Figure 3-2 C&I Only Customer Forecast for Lower Michigan

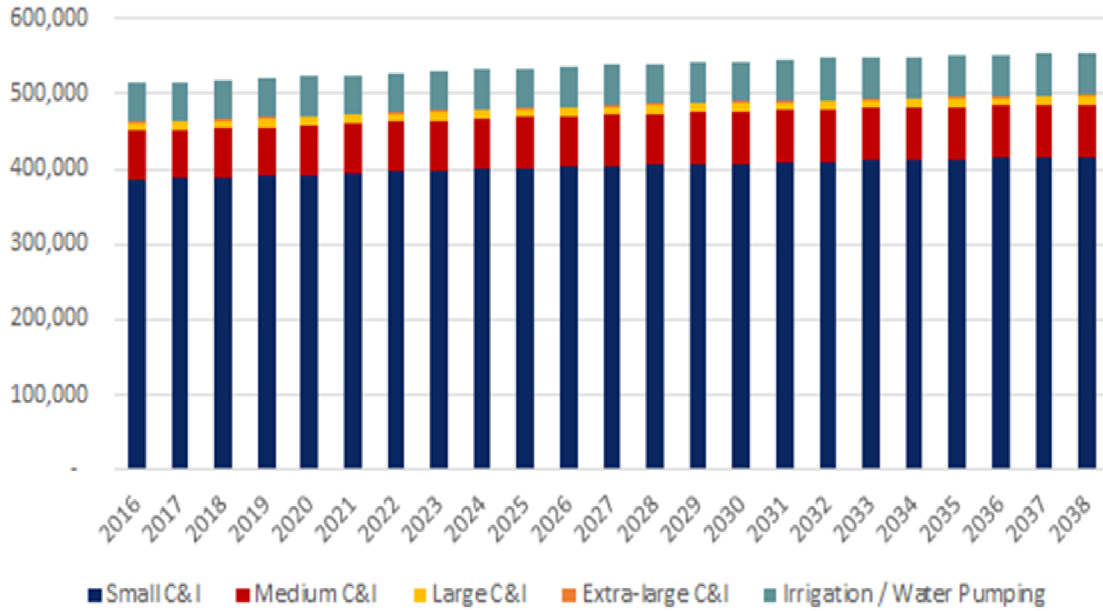


Table 3-1 Customer Forecast by Segment for Lower Michigan

Segment	2016	2020	2025	2030	2035	2037
Residential	4,175,671	4,247,560	4,330,973	4,391,598	4,446,944	4,466,348
Small C&I	385,371	391,922	400,770	407,578	412,974	414,628
Medium C&I	65,303	66,414	67,913	69,067	69,981	70,261
Large C&I	10,315	10,490	10,727	10,909	11,054	11,098
Extra-large C&I	1,671	1,699	1,738	1,767	1,791	1,798
Irrigation / Water Pumping	51,092	51,961	53,134	54,037	54,752	54,971
Total	4,689,424	4,770,046	4,865,255	4,934,956	4,997,495	5,019,105

Figure 3-3 Customer Forecast for Upper Michigan

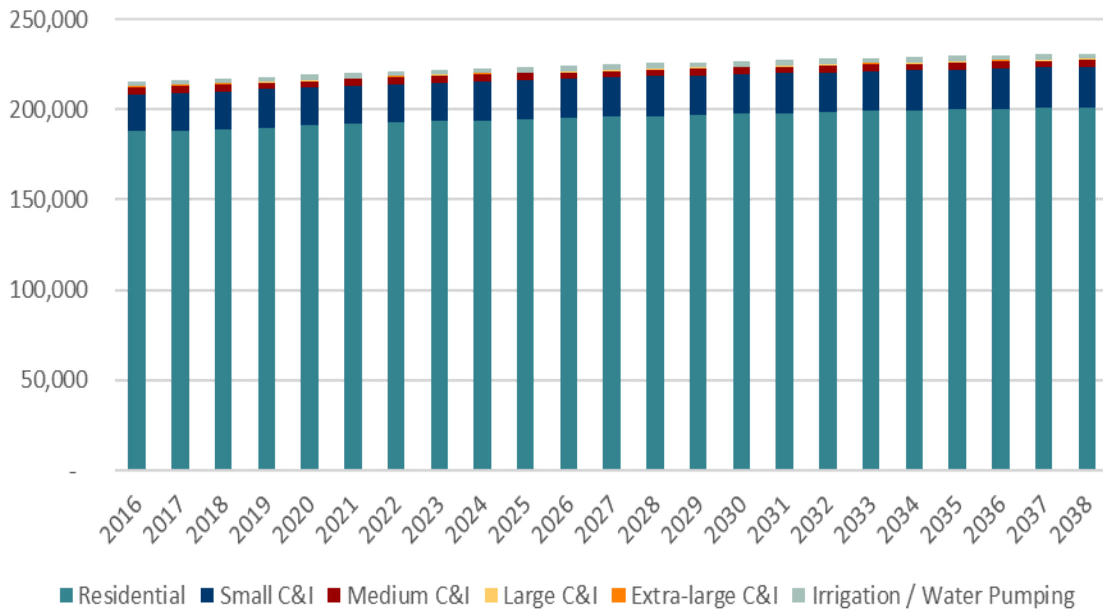


Figure 3-4 C&I Only Customer Forecast for Upper Michigan

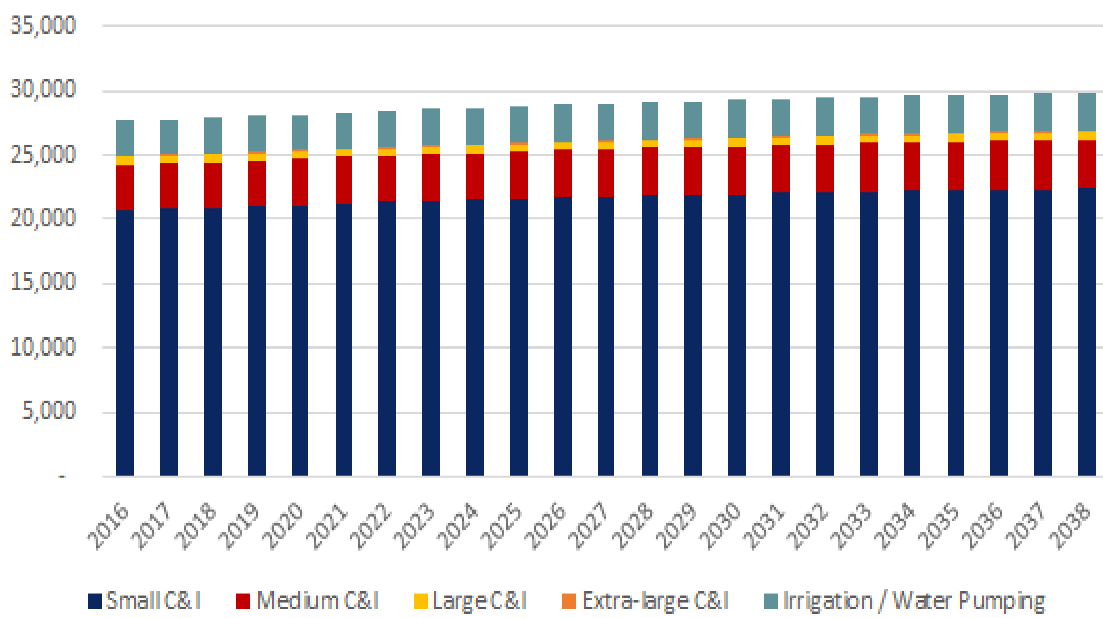


Table 3-2 Customer Forecast by Segment for Upper Michigan

Segment	2016	2020	2025	2030	2035	2037
Residential	187,775	191,008	194,759	197,485	199,974	200,846
Small C&I	20,761	21,115	21,593	21,961	22,253	22,342
Medium C&I	3,518	3,578	3,659	3,721	3,771	3,786
Large C&I	556	565	578	588	596	598
Extra-large C&I	90	92	94	95	96	97
Irrigation / Water Pumping	2,753	2,799	2,863	2,912	2,950	2,962
Total	215,452	219,157	223,545	226,762	229,639	230,631

Demand Forecast

Like the customer load forecast, the demand forecast was established using a combination of utility and EIA data. AEG worked to establish a history for peak summer and winter demand between 2013 and 2015 to provide the foundation against which to measure. Once a historical picture was established, utility growth data was used to forecast the historical values forward to represent the entire state. This resulted in a flat forecast of 22,590 MW in 2018 to 22,903 MW in 2037.

Figure 3-5 Forecasted Peak Demand for the State of Michigan (MW)

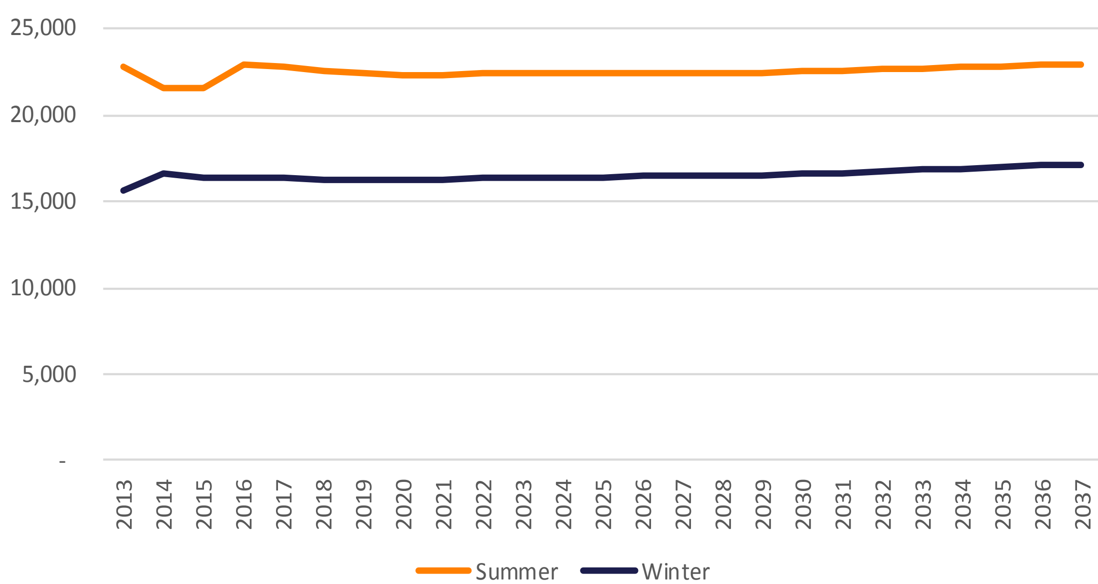


Table 3-3 Peak Demand of the State of Michigan

Season	2016	2020	2025	2030	2035	2037
Summer	22,930	22,300	22,392	22,512	22,812	22,903
Winter	16,391	16,282	16,377	16,611	16,975	17,123

Embedded Demand Response

The flat peak demand forecast is becoming more typical across the country as the growth of distributed energy resources, energy efficiency, and demand response programs lower the growth of peak demand. It is very important to note that both the state-level and regional forecasts represent a demand forecast that includes existing utility DR resources and an embedded forecast for DR resources.

Based on the data provided by the utilities as part of the data request regarding their current program enrollment, and the information we extracted from recent filings we estimate that there is a current existing capacity of 851 MW, and a total embedded forecasted capacity of about 1,277 MW in 2037. Table 3-4 presents the embedded existing capacity resulting from existing and future programs at Consumers Energy and DTE.

Table 3-4 Peak Demand of the State of Michigan at the Generator

Utility / Program	2017	2018	2019	2020	2021 – 2037
DLC					
Consumers	34	77	120	165	222
DTE	108	150	208	225	245
Total DLC	*144*	*227*	*328*	*389*	*467*
Curtailment					
Existing Programs	651	647	647	646	644
New Consumers	56	111	167	167	166
Total Curtailment	*708*	*759*	*814*	*813*	*810*
Existing Capacity	**851**	**986**	**1,142**	**1,203**	**1,277**

Regional Demand Forecasts

With a state-level forecast established, the next step was to breakdown the forecast into separate forecasts for the upper and lower peninsulas. We utilized the historical data for each utility in Michigan to establish an upper and lower peninsula summer and winter ratio. This resulted in an allocation of 98.4% of summer demand and 97.8% of winter demand to the lower peninsula with the upper peninsula receiving the balance of 1.6% and 2.2%.

Figure 3-6 Lower and Upper Peninsula Forecasted Peaks (MW)

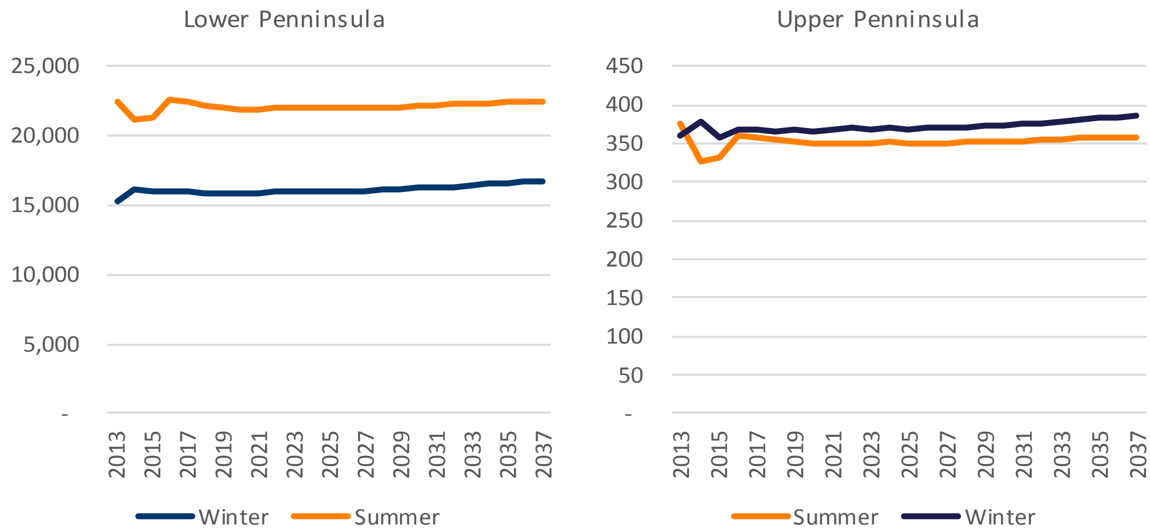


Table 3-5 Peak Demand Forecast by Region

Region	Program	2016	2020	2025	2030	2035	2037
Upper	Summer	360	350	351	353	358	359
	Winter	369	367	369	374	383	386
Lower	Summer	22,570	21,950	22,041	22,159	22,455	22,544
	Winter	16,021	15,915	16,008	16,237	16,592	16,737

The upper and lower peninsulas have different profiles when looking at the ratio of summer peak demand to winter peak demand. This could likely be attributed to more prevalence of electric heating in the upper peninsula. Finally, the forecasts for the upper and lower peninsulas were broken down into the various segments included in the study. Due to the specific segmentation requirements of the study, AEG used secondary sources to break down the forecast. The resulting segment level forecasts are then used as the benchmark to estimate potential. It was critical to make sure that the forecast was accurate and reliable. AEG solicited feedback from the utilities and PSC staff to ensure consensus was reached on the forecast. Since the growth rate was created using forecasts from the two largest utilities, it was deemed to be acceptable and representative of the state.

Figure 3-7 Summer Peak Demand Forecast for Upper Michigan by Segment (MW)

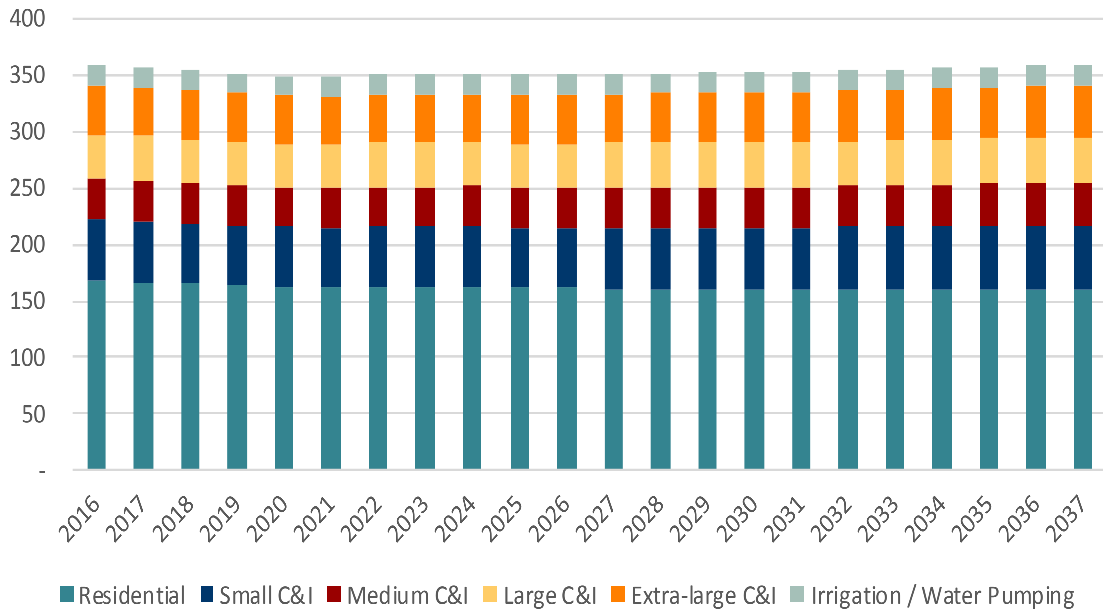


Table 3-6 Summer Peak Demand of the Upper Peninsula by Segment

Segment	2016	2020	2025	2030	2035	2037
Residential	168	163	162	160	161	161
Small C&I	54	53	54	55	56	56
Medium C&I	36	35	36	36	37	37
Large C&I	39	38	39	39	40	41
Extra-large C&I	44	43	44	44	45	46
Irrigation / Water Pumping	18	17	18	18	18	19
Total	360	350	351	353	358	359

Figure 3-8 Summer Peak Demand Forecast for Lower Michigan by Segment (MW)

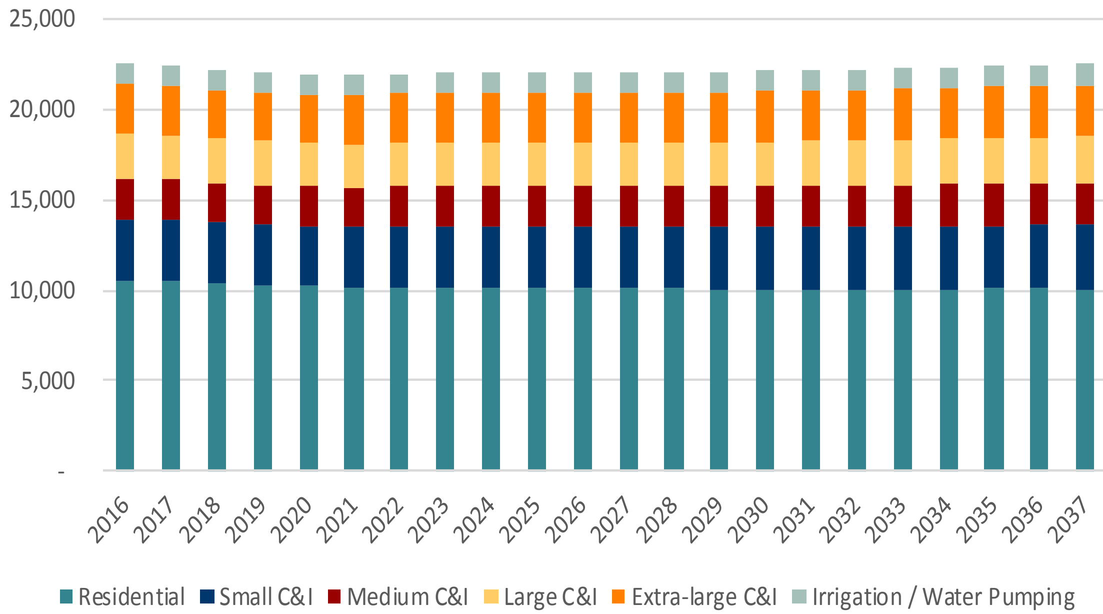


Table 3-7 Summer Peak Demand of the Lower Peninsula by Segment

Program	2016	2020	2025	2030	2035	2037
Residential	10,551	10,229	10,143	10,064	10,086	10,085
Small C&I	3,413	3,328	3,378	3,434	3,512	3,538
Medium C&I	2,261	2,205	2,238	2,275	2,327	2,344
Large C&I	2,456	2,395	2,431	2,471	2,527	2,546
Extra-large C&I	2,769	2,700	2,741	2,787	2,850	2,870
Irrigation / Water Pumping	1,121	1,093	1,109	1,128	1,153	1,162
Total	22,570	21,950	22,041	22,159	22,455	22,544

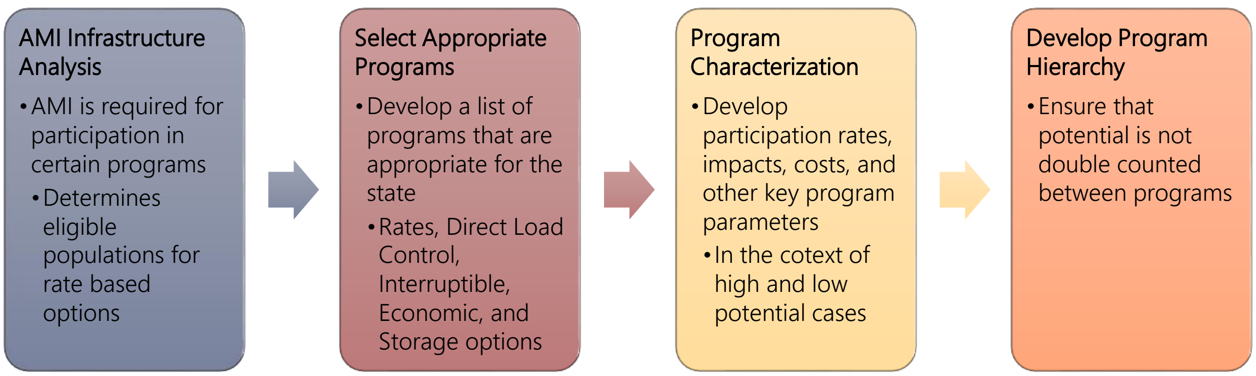
The baseline forecast sees lowering demand over the period of 2016-2019 before growth begins to slowly increase again. The effects of energy efficiency and shifting consumption patterns can be measured directly from this forecast: for a 7.2%-7.8% increase in total meters, total demand will only grow by 1.4% over the same time-frame given the DR resources already embedded in the forecast. However, DR programs and the load management they provide will likely play a critical role in this future as plant retirements, the effect of intermittent renewable generation, and grid constraints will still be factors in ensuring grid reliability.

4

DEVELOP DR PROGRAMS

Developing and characterizing the demand response programs is one of the important pieces of the potential analysis. During this process, we develop the program assumptions that define the programs, how they operate, what they cost, who can participate, and ultimately determine the amount of potential. We develop our assumptions based on the market research conducted for this study, when possible, or on secondary sources.[8] Figure 4-1 presents the four key aspects of this process.

Figure 4-1 Key Elements of the Program Characterization Process



Each step in the analysis is described in the subsections that follow.

Automated Metering Infrastructure Analysis

The demand response programs proposed as part of this study can be categorized into two groups: those where performance is achieved by customer action and, those where performance is driven by a utility-controlled device. For example, most pricing programs are driven by customer response – each participant makes their own decision as to whether to respond and the utility can only induce but not force a customer in these programs to respond to price signals with a reduction in load. On the other side of the spectrum are programs that are entirely run by a utility with no customer input, such as voltage optimization. This program operates entirely at the utility's discretion as they control the switches and transformers that respond to event signals. Programs that are outside of the utility's direct control require AMI metering to evaluate a customer's response. These meters provide the granular, hourly or 15-minute interval data required to determine precise response rates and enable the program to operate effectively.

[8] Appendix A lists all of the studies that we referenced when developing the program assumptions.

Table 4-1 Program AMI Requirements

Program	AMI or Interval Data Required	AMI Preferred
Ancillary Services	Yes	Yes
Battery Energy Storage	No	No
Behavioral	No	Yes
Curtailment Agreements	Yes	Yes
Emergency Curtailment	Yes	Yes
Demand Buyback	Yes	Yes
DLC Central AC	No	Yes
DLC Smart Appliances	No	Yes
DLC Smart Thermostats	No	Yes
DLC Water Heating	No	Yes
Irrigation Load Control	No	Yes
Real Time Pricing	Yes	Yes
Thermal Energy Storage	No	No
Time-of-Use Rates	Yes	Yes
Peak Time Rebate	Yes	Yes
Variable Peak Pricing Rates	Yes	Yes
Voltage Optimization	No	No

For this study, each program was evaluated in two ways with respect to AMI. First, we asked whether AMI (or interval data) required for the operation and/or billing of the program. Second, we asked if AMI would enhance the utilities' ability to evaluate the program and/or measure the impacts of the program. Table 4-1, left, presents the listing of each program and whether it would require AMI, and whether AMI would be preferred for measurement and evaluation purposes.

Programs such as Direct Load Control of Central Air Conditioners (DLC-AC) would not necessarily require AMI metering – that is they can be operated and customers can receive accurate bills without the presence of AMI. However, these types of programs would be able to leverage AMI data for evaluation purposes. Other programs, specifically any program or rate that needs accurate information on customer consumption by time of use, would require AMI to determine precisely how much energy was used during events or on-peak periods.

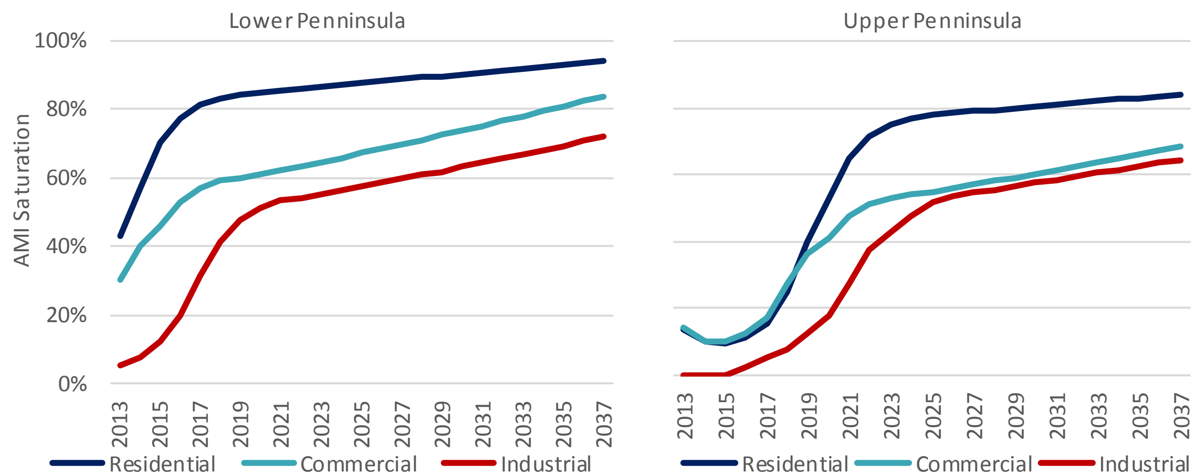
Of the 17 programs evaluated in this study, eight of them were determined to require AMI meters to operate. An additional six would benefit from AMI for evaluation and measurement purposes.

In addition, AMI metering can be used to enhance customers' understanding of how and when they use energy, thereby enabling them to respond to program signals easily and efficiently. While not explicitly considered as part of this study, several types of behavioral programs currently offer this type of customer education, or engagement.

Considerations for Modeling

Within the modeling framework, the saturation of AMI meters acts as an upper bound for the participation level for the eight programs which were identified as programs that require AMI metering for operations. The upper bound acts as a gatekeeper for the program: customers are not allowed to sign up for the program unless they already have an AMI meter installed. To determine where the upper bound lies, AEG created an AMI saturation forecast for the upper and lower peninsula across the residential, commercial, and industrial sectors. The forecast was created using a combination of EIA-861 data and a consensus forecast to determine projected AMI saturations used in the study. For commercial and industrial customers, these saturations apply only to small and medium sized customers since in nearly all cases, large and extra-large C&I customers already have legacy interval meters for billing.

Figure 4-2 AMI Saturation Forecasts in Lower and Upper Peninsula



The forecasts assume that the deployment of AMI in the upper peninsula will follow the pattern set by the lower peninsula. Likewise, an assumption was made that AMI meters would follow a normal technology diffusion curve with the lower peninsula already seeing widespread adoption and the upper peninsula slowly beginning to see diffusion as well.

Select the Appropriate Programs

This study considered a comprehensive list of demand response programs available in the DSM marketplace today and projected into the 20-year study time horizon. These are controllable or dispatchable programmatic options where customers agree to reduce, shift, or modify their load during a specific number of hours throughout the year. We also considered Ancillary Services and Voltage Optimization programs, which operate during different times and for different reasons than a traditional peak load management program. We present each of the final DR options that are included in this study and briefly describe each option in Table 4-2 below.

Table 4-2 Comprehensive list of Demand Response Options

Program Option	Eligible Customer Segments	Mechanism
Behavioral DR (BDR)	Residential	Voluntary DR reductions in response to behavioral messaging. Example programs exist in CA and other states. Requires AMI technology.
Direct Load Control (DLC) of air conditioners (A/C) and domestic hot water (DHW)	Residential, Small and Medium C&I	DLC switch installed on customer's equipment
DLC with two-way communicating or Smart T-stats	Residential, Small C&I	Internet-enabled control of thermostat set points, can be coupled with any dynamic pricing rate
Smart Appliance DLC	Residential, Small C&I	Internet-enabled control of operational cycles of white goods appliances
Emergency Curtailment Agreements	Large C&I, Extra-large C&I	Customers enact their customized, mandatory curtailment plan. May use stand-by generation. Penalties apply for non-performance.
Capacity Bidding	Large C&I, Extra-large C&I	Customers volunteer a specified amount of capacity during a predefined "economic event" called by the utility in return for a financial incentive.
Irrigation Load Control	Irrigation / Water pumping	Automated pump controllers
Time-of-use Rates	Residential, All C&I, Irrigation	Higher rate for a particular block of hours that occurs every day. Requires either on/off peak meters or AMI technology.
Variable Peak Pricing	Residential, All C&I, Irrigation	Much higher rate for a particular block of hours that occurs only on event days. Requires AMI technology.
Peak Time Rebate	Residential, Small C&I	Rebate for reduction in energy usage over baseline on event days. Requires AMI technology.
Real-time Pricing	Large, Extra-large C&I	Dynamic rate that fluctuates throughout the day based on energy market prices. Requires AMI technology.
Demand Buyback	Medium, Large C&I, Extra-large C&I	Customers enact their customized, voluntary curtailment plan. May use stand-by generation. No penalties for non-performance. Requires AMI technology.
Thermal Energy Storage	All C&I	Peak shifting of primarily space cooling loads using stored ice or cold water
Battery Energy Storage	All segments	Peak shifting of loads using stored electrochemical energy
DR providing ancillary services (Fast DR)	All segments	Automated, fast-responding curtailment strategies with advanced telemetry capabilities suitable for load balancing, frequency regulation, etc.
Voltage optimization technologies	All segments / Distribution side resources	Automated technologies adjust voltage levels (particularly for EOL locations) to maintain power quality while saving energy.

Program Descriptions

For each program option identified above in Table 4-2 we present a description of the program as it has been characterized in this study.

Behavioral Demand Response (BDR)

BDR is structured like traditional demand response interventions, but it does not rely on enabling technologies nor does it offer financial incentives to participants. Participants are notified on an event, and simply asked to reduce their consumption during the event window. Generally, notification occurs the day prior to the event and may employ a phone call, email, or text message. The next day, customers receive post-event feedback that includes personalized results and encouragement.

For this analysis, we assumed the BDR program would be offered as part of a Home Energy Reports program in a typical opt-out scenario. The low participation case represents a more conservative deployment, likely targeting participants with the most potential, while the high participation case represents a more aggressive deployment. Thus, the impacts of the high case were reduced to reflect a combination of high and low energy users.

Direct Load Control (DLC)

This study addresses DLC of several end-uses including, space cooling, water heating, smart appliances, and smart thermostats. Several utilities within the State of Michigan currently implement a direct load control program for central space cooling. Our analysis addresses the existing capacity from these programs, and removes this capacity from the potential. The analysis caps customer participation in DLC space cooling by ensuring that population applies to a subset of customers in DLC CAC and DLC Smart Thermostats does not exceed our market research results. Direct load control events represent an eight-hour window in which units are cycled, in return customers receive an annual incentive of $25 for the low case and $50 for the high case.

Space Cooling and Water Heating

Space cooling and water heating apply to the residential and small C&I segments. Each of these programs use a switch technology that is directly applied to the cooling, or water heating unit. During a peak event, a one-way radio signal is sent from the utility to the switch that cycles the unit on and off. This is done without the customer involvement and typically without the customer being aware an event is happening.

DLC of Smart Thermostats

Smart thermostats were included for residential and small C&I customers only. Generally, larger C&I customers would have more sophisticated cooling units which cannot be controlled using a domestic thermostat. Smart thermostats, like those offered by Nest and Ecobee, provide two-way communication between the customer and the utility. Smart thermostats offer messaging, customer override options, and additional temperature control which is not an option for switches. Generally, a setback strategy is used during events, such that when a signal is sent to the thermostat it alters the target temperature by a pre-specified amount. When the thermostat is "set back" the AC unit turns off, but will resume operation as soon and the indoor temperature reaches the new set point.

DLC of Smart Appliances

In addition, Smart appliance DLC was included for residential customers only. With technology advances, direct load control programs can now utilize "smart" home devices that interact with home appliances, such as refrigerators, dishwashers, and clothes washers. The process is similar to that used with a traditional switch, except the utility sends a signal to the smart appliance via wifi to curtail the appropriate load during peak events. This is an emerging technology and program; therefore, our modeling reflects conservative estimates for participation.

Emergency Curtailment Agreements

Under this program option, it is assumed that participating customers will agree to reduce demand by a specific amount or curtail their consumption to a predefined level at the time of an event. In return, they receive a fixed incentive payment in the form of capacity credits or reservation payments (typically expressed as $/kW-month or $/kW-year), they may also receive payment for energy reduction. The amount of the capacity payment typically varies with the load commitment level. Because it is a firm, contractual arrangement for a specific level of load reduction, enrolled loads represent a firm resource and can be counted toward installed capacity requirements. Customers are paid to be on call even though actual load curtailments may not occur and penalties are assessed for under-performance or non-performance. Events may be called on a day-of or day-ahead basis as conditions warrant for emergency capacity reasons. Emergency events are called in response to an emergency at the wholesale level.

The current curtailment agreement programs within the state are primarily captured within the Emergency Curtailment program for this analysis. Within Michigan, commercial and industrial customers have signed contracts with their utilities to curtail a specific amount of capacity during infrequent "emergency events" as defined by the individual utility. The analysis modeled and removed the current and forecasted capacity from the incremental potential for the emergency curtailment programs occurring within Michigan. Our interviews with Michigan utilities revealed that emergency events are rarely called.

Capacity Bidding

Capacity Bidding is similar to Emergency Curtailment in that customers receive a capacity payment for a pre-specified amount of load reduction, but in response to an economic event as defined by the utility. Economic events are typically called when the wholesale price of electricity is higher than the cost paid out to the demand response customers. Customers also generally receive an energy payment based on the amount of load reduced during an event. However, customers usually do not enter into a contractual agreement directly with the utility therefore penalties are generally not assessed for non-performance. Capacity Bidding programs are also generally called much more often than an Emergency Curtailment program.

Irrigation Load Control

Irrigation Load Control is a peak-reduction program that enrolls agricultural customers to encourage them to shift use to off-peak hours. Customers who enroll in this program earn cash incentives for temporarily reducing electricity use by shutting off irrigation pumps during peak demand periods. The irrigation load control program was modeled as a lower-technology option in which customers have one-way switches placed on the system pumps.

Time of Use

Time of Use (TOU) is an electric rate that varies based on the time of day to reflect the varying cost to utility of supply. Typically, electricity cost of supply is higher during peak hours and they are lower during non-peak hours. Time-of-use rates require either an on/off peak meter or AMI technology. For our analysis, we require AMI meters since most utilities are considering AMI deployments, rather than installing on/off peak meters on a case by case basis.

In this analysis, the time-of-use rate is available to all customer classes in both low and high cases. The low case represents an opt-in rate where customers volunteer to participate. While participation in this case is lower, the impacts are higher because those customers who have opted-in are most likely more willing to shift and/or reduce load. The high case represents an opt-out rate where customers are assigned to the rate and can choose to opt-out for residential, small and medium C&I, and irrigation customers. For large and extra-large C&I customers, the time of use rate is mandated, which is typical in most implementation scenarios. For the high case, we assume average impacts are lower on a per-customer basis because participants include highly motivated customers, but also those who are more reluctant to reduce and / or shift usage to off-peak hours.

Variable Peak Pricing

Variable Peak Pricing (VPP) is a time-based electric rate. On VPP rate, the price of electricity will vary by time of use, but also by day, including critical events and pricing on the highest load days. The variable peak pricing program is applicable to all customer segments. The low case represents a low-cost option with a lower penetration of enabling technology. Participation is lower and less customers have a wi-fi enabled thermostat, meaning a lower per customer peak demand impact. The high case is a more aggressive case in which higher levels of marketing achieves a higher participation rate and higher technology penetration.

Peak Time Rebate

A Peak Time Rebate (PTR) program provides incentives to customers who reduce their usage during peak day events. The rebate is typically offered for kWh reductions during the peak event and penalties are not assessed for customers who do not have measurable reductions. Expected reductions from this program without technology are typically small. This rebate program was modeled for residential and small C&I customers who opt-into the program. The low and high cases represent a no-technology option. The program was modeled to be incremental to participants in DLC and VPP customers who already have technology. In addition, customer participation in VPP and PTR were capped at the market research participation take rates as to ensure our modeling efforts are not over counting likely customer participation.

Real Time Pricing

Real-time pricing (RTP) is a time based electric rate that reflects price changes from hour to hour that a utility encounters in an energy market. These prices are passed along to the customer and the customer has the opportunity to shift or reduce their usage in response to the prices; for example, scheduling usage during periods of low demand to pay cheaper rates. Customers are given the option to participate with and without a wi-fi enabled technology and require AMI meters. Our market research and industry experience indicate that participation in this pricing option is usually low, as this type of pricing option typically resonates with more sophisticated large users, because they are the customer types who typically have the ability to adjust their usage cost effectively. Our modeling reflects limited customer participation. program for large and extra-large customer segments only.

Demand Buyback

The Demand Bidding/Buyback is a pay for performance program that encourages C&I consumers to reduce their consumption during events in return for energy payments. Events are typically scheduled on a day-ahead basis and can be quite frequent. This low risk option allows customers to control their participation by submitting a load reduction bid indicating the amount of kW the customer will reduce for each hour of the demand bidding event. Utilities set a minimum reduction requirement. This program was modeled for medium, large, and extra-large C&I customers.

Thermal Storage

Thermal energy storage (TES) shifts the production of cooling to off-peak hours. It uses standard cooling equipment to chill water or make ice during off-peak hours and stores the water or ice in a storage tank. During the on-peak hours, the storage is "discharged" to meet cooling load in on-peak hours. A time-of-use rate is essential to the success of this option to create the financial incentive for customers to invest in the storage needed for the system. This technology was first introduced in the 1980s and had limited success at the time, in part because some utilities rescinded the promotional TOU rates. TES is re-emerging and now being considered across the country. Therefore, participation estimates remained conservative for the duration of the study timeline. Please note that TES also exists for residential space heating. However, the success is limited and therefore not considered for this study.

Battery Storage

Battery Storage works when electrical energy is stored during times when production (especially from intermittent sources such as renewable electricity sources such as wind power or, solar power) exceeds consumption, and is returned to the grid when production falls below consumption. Behind-the-meter or customer sited battery storage functions in a similar fashion on a smaller scale. Utilities would call a peak event and customers would activate the energy stored on the battery. For this analysis, utilities would pay for the cost of the battery in exchange for the ability to call on the battery during peak events.

Battery Storage is an emerging technology with low penetration and high costs, although based on our research, costs are expected to come down and penetration is expected to increase over time. Estimations of how long this will take are varied, therefore for this analysis the participation was kept conservative and a longer program participation ramp up period was applied. A cost deflator was applied to model the expected reduction of costs.

Ancillary Services

Ancillary Services refer to functions that help grid operators maintain a reliable electricity system. Ancillary services maintain the proper flow and direction of electricity, address imbalances between supply and demand, and help the system recover after a power system event. In systems with significant variable renewable energy penetration, additional ancillary services may be required to manage increased variability and uncertainty.

Voltage Optimization

Voltage Optimization is completely different from the previously described customer based programs. The technology is operated on the distribution side of the meter and achieves savings without any interaction with or action by customers.

Voltage optimization enables systems to reduce voltage by reducing energy use, power demand and reactive power demand. Voltage optimization devices could have a fixed voltage adjustment or regulated electronically. Voltage optimization systems are typically installed in series with the mains electrical supply to a building, allowing all its electrical equipment to benefit from an optimized supply.

For this analysis, a high-level approach was taken to model the implementation of voltage optimization for demand response benefits. The low case represents a lower cost, lower roll out of VO on a select number of constrained feeders. The high case represents a higher cost, more intensive roll out of VO on all viable feeder candidates. Our modeling costs represents the portion of total upgrade costs that were allocated by the avoided kW costs. This was done to ensure that the demand response program does not bear the full weight of a program that a utility would implement for a variety of reasons, not just demand response.

Program Characterization

In this section, we characterize each program with respect to the high and low potential cases. First, we describe the differences between the two cases at a high level. Then, we present the key assumptions for each program as they pertain to participation, impacts, and costs.

High and Low Potential Cases

We estimated two types of realistic achievable potential as part of this study- the "high" case and the "low" case. In each case, we adjusted our assumptions surrounding one of five key program attributes:

- Participation rates or take rates
- Per customer impacts; participant incentives
- Penetration of enabling technologies such as switches or smart thermostats
- Per customer costs

In Table 4-3 below we present the directional movement of each of the key program inputs as it pertains to the high case, relative to the low case. It is informative to look at changes in these inputs qualitatively prior to looking at the detailed assumptions as they are presented in the program characterization section.

Table 4-3 Changes in Key Program Inputs in the High Case

Program and Class	Participation	Impact/Cust.	Incentive	Technology	Cost/Cust.
Behavioral	↑	↓	-	-	↑
DLC[9] [10]	↑	-	↑	-	↑
Curtailment	↑	-	-	-	-
Irrigation Load Control	↑	-	↑	-	↑
Time of Use (R, Sm/Med)	↑ *(opt-out)*	↓	-	-	-
Time of Use (Large C&I)	↑ *(mandatory)*	↓	-	-	-
VPP and RTP (R, Sm/Med)	↑	↑	-	↑	↑
VPP and RTP (Large C&I)	↑	-	-	-	↑
Demand Buyback	↑	-	↑	-	↑
Thermal Storage	↑	-	-	-	↑
Battery Storage	↑	-	-	-	↑
Voltage Optimization	↑	-	-	-	↑
Ancillary Services[11]	↑	-	↑	-	↑

- Participation rates. In general, we assume participation rates increase across the board in the high case, vs. the low case. For the TOU program we also assume an opt-out participation rate in the residential, and SMB segments, and a mandatory participation rate in the large and extra-large C&I segments.
- Per customer impacts. In most cases for the high case, we assume that the impacts are higher or the same as the low case. However, under opt-in or mandatory rate structures, per customer impacts

[9] For the water heating DLC program incentive costs were not increased as the increased incentive resulted in a non-cost-effective program. In this case we kept the program in the high case, but did not increase participation, incentives, or marketing costs.

[10] For the small commercial DLC program, a varied incentive was not supported by the market research so the incentive is the same in the low and high cases.

[11] Because Ancillary Services in outside the cost effectiveness screen, the arrows represent qualitative increases only.

generally decrease substantially since a larger portion of the participants is likely to have low or zero impacts.

- Incentives. For programs where there is an annual or event-based incentive, we assume that the incentive is larger in the high case relative to the low case. This larger incentive may result in increased participation, larger impacts, or both.
- Technology. For the VPP program, we assume that participants in the high case have a higher penetration of enabling technologies, such as smart thermostats, to help them respond to price signals.
- Per customer costs. In most cases, the per customers costs are also larger in the high case, due to higher marketing costs, which in turn drive higher participation, or because of higher incentive costs.

Participation Rate Assumptions

In Table 4-4 to Table 4-6 we present the participation rate assumptions for each program under both the high and the low case. It is important to note that the percentage in the tables indicates the percentage of the eligible population that we assume will participate in each option. The eligible population reflects appliance saturation rates (e.g., the share of customers with electric water heating) and the program hierarchy, described in the next section. In addition, for existing programs, the participation rates in the table represent incremental participation.

Table 4-4 Participation Rates – DLC and Curtailment Programs

Customer Class	Program Option	Participation Low Case	Participation High Case
Residential	Behavioral	20.0%	50.0%
Residential	DLC Central AC	19.6%	23.8%
Small C&I	DLC Central AC	6.0%	7.2%
Residential	DLC Water Heating	23.0%	23.0%
Small C&I	DLC Water Heating	6.0%	6.0%
Residential	DLC Smart Thermostats	3.5%	4.2%
Small C&I	DLC Smart Thermostats	1.1%	1.6%
Residential	DLC Smart Appliances	5.0%	7.5%
Small C&I	DLC Smart Appliances	3.8%	5.6%
Large C&I	Emergency Curtailment	6.3%	6.3%
Extra-large C&I	Emergency Curtailment	34.9%	34.9%
Irrigation & Water Pumping	Irrigation Load Control	5.0%	10.0%

In Table 4-4 above we present the participation rates for the DLC and Curtailment programs. For the residential class, participation rates were benchmarked to the market research we conducted for this study. In addition, it is important to note that total participation in DLC of Cooling and Smart Thermostats was capped at 23% in the low case and 28% in the high case to account for the fact that those two programs target the same load.

In general. participation rates for small C&I customers are much lower than for residential customers, which reflects the fact that these customers are harder to engage in demand response.

In Table 4-5, we present the participation rates for the rate based or economic dispatch options. Recall that for TOU, the low case represents an opt-in program, with much lower participation rates, while the high case represents an opt-out or mandatory case with much higher participation rates. Also note that the participation rates above only apply to the eligible population of customers with AMI. Low participation rates for residential and large C&I are based on the market research results, while the participation rates for the remaining segments were benchmarked to participation in similar programs.

Table 4-5 Participation Rates – Rate Based or Economic Dispatch Options

Customer Class	Program Option	Participation Low Case	Participation High Case
Residential	Time-of-Use Rates	30.0%	75.0%
Small C&I	Time-of-Use Rates	13.0%	60.0%
Medium C&I	Time-of-Use Rates	13.0%	60.0%
Large C&I	Time-of-Use Rates	40.0%	75.0%
Extra-large C&I	Time-of-Use Rates	40.0%	75.0%
Irrigation & Water Pumping	Time-of-Use Rates	13.0%	50.0%
Residential	Variable Peak Pricing Rates	6.8%	24.1%
Small C&I	Variable Peak Pricing Rates	6.3%	7.0%
Medium C&I	Variable Peak Pricing Rates	19.0%	22.0%
Large, Extra-large C&I	Variable Peak Pricing Rates	10.0%	15.0%
Irrigation and Water Pumping	Variable Peak Pricing Rates	5.0%	15.0%
Residential	Peak Time Rebate	20.3%	8.0%
Small C&I	Peak Time Rebate	6.3%	7.0%
Large and Extra-large C&I	Real Time Pricing	5.0%	10.0%
Medium C&I	Demand Buyback	18.0%	24.0%
Large and Extra-large C&1	Demand Buyback	15.0%	20.0%
Large C&I	Capacity Bidding	12.0%	16.0%
Extra Large C&I	Capacity Bidding	30.0%	40.0%

Finally, in Table 4-6 we present the participation rates for the storage programs, Ancillary Services, and Voltage Optimization. Participation in these programs was determined based on secondary sources in combination with PSC's market research with large customers. Voltage Optimization is very difference from the other programs and in this case, the participation rate represents the percentage of customers that would be on circuits that have the VO technology.

Table 4-6 Participation Rates – Storage and Other Programs

Customer Class	Program Option	Participation Low Case	Participation High Case
Small and Medium C&I	Thermal Energy Storage	1.5%	4.5%
Large and Extra-large C&I	Thermal Energy Storage	1.5%	4.5%
All sectors	Battery Energy Storage	5.0%	10.0%
Residential	Ancillary Services	15.0%	22.0%
All C&I	Ancillary Services	7.5%	11.0%
Irrigation and Water Pumping	Ancillary Services	3.0%	5.0%
All Sectors	Voltage Optimization	25.0%	50.0%

Per-customer Impact Assumptions

In Table 4-7 to Table 4-9 we present the per-customer impact assumptions for each program under both the high and the low case. The per customer impacts are presented as percentages which reflect the total load reduction during an event. The impacts in the tables below are each benchmarked to similar programs operating in the industry today. If the program is currently being implemented in the state, we used the actual average per customer impacts for that program as provided by the utilities.

Table 4-7 Per-customer Impacts – DLC and Curtailment Programs

Customer Class	Program Option	Impacts Low Case	Impacts High Case
Residential	Behavioral	2.0%	1.5%
Residential	DLC Central AC	38.1%	38.1%
Small C&I	DLC Central AC	10.9%	10.9%
Residential	DLC Water Heating	22.4%	22.4%
Small C&I	DLC Water Heating	6.4%	6.4%
Residential	DLC Smart Thermostats	29.1%	29.1%
Small C&I	DLC Smart Thermostats	8.3%	8.3%
Residential	DLC Smart Appliances	6.2%	6.2%
Small C&I	DLC Smart Appliances	0.9%	0.9%
Large C&I	Emergency Curtailment	22.1%	22.1%
Extra-large C&I	Emergency Curtailment	65.0%	65.0%
Irrigation & Water Pumping	Irrigation Load Control	50.0%	50.0%

Table 4-8 Per-customer Impacts – Rate Based Programs

Customer Class	Program Option	Impacts Low Case	Impacts High Case
Residential	Time-of-Use Rates	12.2%	4.9%
Small C&I	Time-of-Use Rates	0.3%	0.1%
Medium C&I	Time-of-Use Rates	4.2%	1.7%
Large C&I	Time-of-Use Rates	4.9%	2.0%
Extra-large C&I	Time-of-Use Rates	4.9%	1.5%
Irrigation & Water Pumping	Time-of-Use Rates	4.9%	2.9%
Residential, Small and Medium C&I	Variable Peak Pricing Rates	19.0%	28.6%
Large and Extra-large C&I	Variable Peak Pricing Rates	12.6%	12.6%
Irrigation & Water Pumping	Variable Peak Pricing Rates	10.0%	10.0%
Residential	Peak Time Rebate	2.2%	2.2%
Small C&I	Peak Time Rebate	0.5%	0.5%
Large and Extra-Large C&I	Real Time Pricing	12.6%	12.6%
Medium C&I	Demand Buyback	9.2%	9.2%
Large & Extra-large C&I	Demand Buyback	10.0%	12.0%
Large Extra-large C&I	Capacity Bidding	31.1%	35.0%
Extra Large C&I	Capacity Bidding	31.5%	35.0%

Table 4-9 Per-customer Impacts – Storage and Other Programs

Customer Class	Program Option	Impacts Low Case	Impacts High Case
C&I	Thermal Energy Storage	16.4%	16.4%
All Sectors	Battery Energy Storage	70.4%	70.4%
All Sectors	Ancillary Services	4.8%	4.8%
All Sectors	Voltage Optimization	2.0%	2.0%

Program Cost Assumptions

The study considers several types of program costs including the following:

- Marketing costs are associated with enrolling customers in the program. In the high case, we increase the per customer marketing costs by 20% for some programs to reflect the increased effort associated with enrolling additional participants. The low case marketing costs assumptions are:
    - $50 for each residential customer recruited
    - $100 for each C&I customer recruited
- Equipment costs are any costs associated with equipment that would be provided by the utility which enhances or enables customer response, i.e. smart thermostats or switches. Each equipment cost is both program and segment specific and is benchmarked to previous studies, or reports.
- Incentives are paid to customers to encourage them to either sign up for a program or to respond to an event. They could be a one-time or annual payment, as is common in direct load control programs, or they could be paid for each event, like in a Capacity or Demand Bidding program. Each incentive is program specific and benchmarked to existing programs in the industry.
- Administrative costs are estimated based on the number of full-time employees (FTE) that might be needed to run the entire portfolio of programs across the state. We estimated the total number of FTEs based on the current numbers of FTEs employed by Consumers Energy and DTE (14 total) and then added in additional FTEs to represent the rest of the state for a total of 20 FTEs administering DR programs statewide.[12] Next, we allocated the total cost to the programs based on their size and complexity while maintaining a minimum level of fixed cost.
    - Note that the curtailment-style programs include only administrative costs and are estimated as $/MW.
- Development costs for a single program were assumed to be $150,000. We then adjusted the development costs up or down based on the anticipated size and complexity of each program.

Table 4-10 below presents the administrative and development costs by program.

[12] We assumed that smaller utilities would have less than one FTE for their programs.

Table 4-10 Administrative and Development Costs by Program

Program	Variable Cost	Fixed Cost	Total Administrative Costs	Development Cost
DLC Central AC	$243,000	$75,000	$318,000	$75,000
DLC Water Heating	$81,000	$75,000	$156,000	$150,000
DLC Smart Thermostats	$243,000	$75,000	$318,000	$150,000
DLC Smart Appliances	$60,750	$75,000	$135,750	$75,000
Irrigation Load Control	$141,750	$75,000	$216,750	$150,000
Time-of-use Rates	$202,500	$75,000	$277,000	$150,000
Variable Peak Pricing Rates	$172,125	$75,000	$247,125	$150,000
Peak Time Rebate	$172,125	$75,000	$247,125	$150,000
Real Time Pricing	$121,500	$75,000	$196,500	$150,000
Demand buyback	$162,000	$75,000	$237,000	$150,000
Thermal Energy Storage	$121,500	$75,000	$196,500	$150,000
Battery Energy Storage	$121,500	$75,000	$196,500	$150,000
Ancillary Services	$182,250	$75,000	$257,250	$300,000
Voltage Optimization	-	$75,000	$75,000	$300,000
Capacity Bidding			$52,040 / MW	
Emergency Curtailment			$52,040 / MW	

We also consider avoided costs part of our cost benefit screening. We used avoided capacity costs for the state of Michigan that are equal to the cost of new entry, or CONE cost, for MISO LR Zone 7[13] and then escalate those costs at 2% per year. The avoided energy costs were benchmarked to a recent study by the AEE.[14] Table 4-11 presents the avoided capacity and energy costs over the life of the study.

Table 4-11 Avoided Capacity and Energy Costs

Cost	Unit	2017	2018	2019	2020	2021	2022
Avoided Capacity Costs	$/kW @gen	$94.83	$96.73	$98.66	$100.63	$102.65	$104.70
Avoided Summer Energy Costs	$/MWh @gen	$20.00	$20.37	$20.76	$21.27	$21.74	$22.47

Program Hierarchy

The last step in the program characterization is to develop the program hierarchy which prevents double counting the potential estimates among programs. For example, small C&I customers cannot participate in the DLC Space Cooling program and the Thermal Energy Storage program since both programs target the same load from the same end use for curtailment on the same days.

Table 4-12 shows the participation hierarchy by customer sector for applicable DR options. Note that both Emergency Curtailment and Ancillary Services are not part of the hierarchy. This is because both of these programs would generally operate outside typical peak shaving event windows.

[13] "Cost of New Entry PY 2016/17" October 29, 2016 SAWG MISO Presentation. https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20151029/20151029%20SAWG%20Item%2004%20CONE%20PY%202016-2017.pdf

With the hierarchy activated, each successive resource that is run in the model stack has a newly updated pool of eligible participants where customers enrolled in previously-stacked, competing resource options have been removed. The participation rate for that resource is then applied to the new pool of eligible participants, rather than the entire, original pool. Note that Voltage Optimization does not appear in this hierarchy since it operates on the utility side of the meter.

Table 4-12 Program Hierarchy by Segment

Customer Class	Residential	Small C&I	Medium C&I	Large C&I	Extra Large C&I	Irrigation & Water Pumping
DLC Central AC	x	x	x			
DLC Water Heating	x	x	x			
DLC Space Heating						
DLC Smart Appliances	x					
Irrigation Load Control						x
Curtailment Agreements				x	x	
Emergency Curtailment				x	x	
Demand Buyback				x	x	
Thermal Energy Storage			x	x	x	
Battery Energy Storage	x	x	x	x	x	
Time of Use	x	x	x	x	x	x
Variable Peak Pricing	x	x	x	x	x	x
Real Time Pricing						
Behavioral DR	x					

5

DEMAND RESPONSE POTENTIAL

In this chapter, we present the results of our analysis. The chapter is organized as follows:

- First, we discuss our approach to the potential analysis by:
  - Defining the levels of demand response potential estimated in this analysis.
  - Discussing some important aspects of the analysis which should be considered when reviewing the results of this study.
  - Discussing the presentation of the detailed results.
- Then, we present the results of the analysis, first at a high level, and finally with detailed results for each of the three cases.

Potential Analysis Approach

Traditional energy efficiency potential studies usually estimate three levels of potential, technical potential, economic potential, and achievable potential. In the context of a DR potential study, these three levels of potential can be characterized as follows:

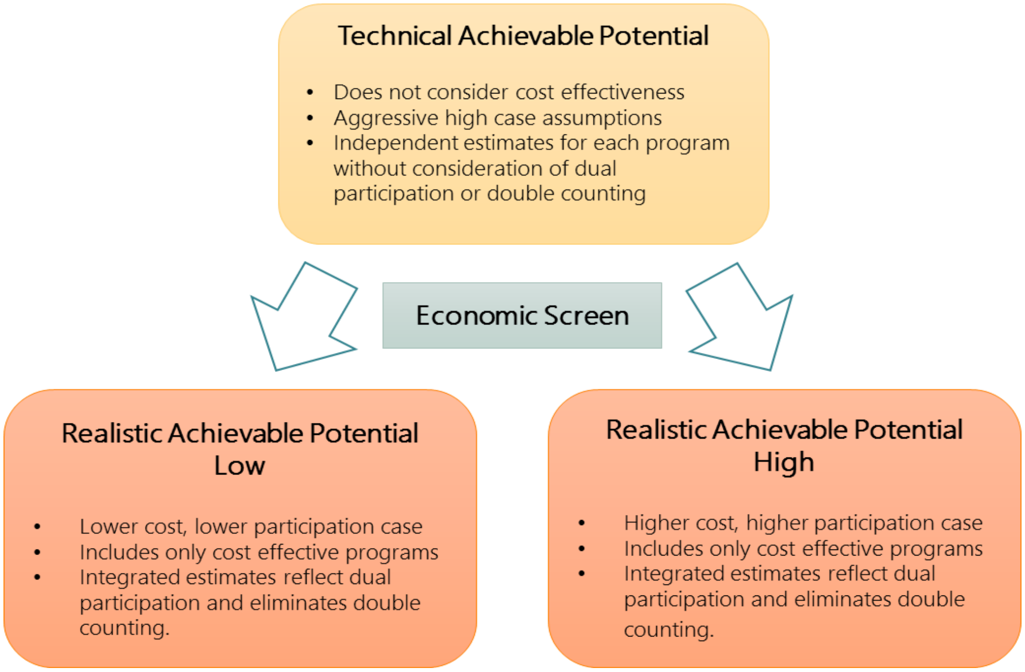
- Technical potential – the total potential that could be realized without consideration of customer willingness to adopt measures or cost effectiveness. This represents 100% participation for the eligible population of each DR program.
- Economic potential – the subset of technical potential that is cost effective.
- Achievable potential – subset of economic potential that is considered realistically achievable when considering customer participation and real-world constraints.

However, in practice we find that the more traditional levels of potential do not provide as much insight into how programs might roll-out in future years. Furthermore, the upper bound of technical potential, is less meaningful than in a typical EE study since it simply represents the case where 100% of all customers participate in a DR program.

Therefore, for this study, we defined three types of potential which we believe lead to more meaningful conclusions and recommendations regarding future DR. It is very important to note that all estimates of DR potential presented in this study are incremental to the existing and forecasted DR from programs that are currently being implemented in the state.

Figure 5-1 below shows the three types of potential estimates that we present as part of this study, and how they are related to each other. Each case is also further described in detail below.

Figure 5-1 Definitions of Levels of Potential Considered in this Study



- Technical Achievable Potential – Stand-Alone Case. Technical achievable potential represents a realistic, upper bound for potential DR attributable to each individual program without consideration of whether the program is cost effective or not. The individual potential estimates cannot be added together since the case also does not account for participation in multiple programs.
- Economic Screen. Each program is assessed for cost-effectiveness using a benefit-cost ratio. The cost-effectiveness of individual programs is assessed with different program-start years until the first cost-effective year is identified. Demand savings are realized only in cost-effective years. Once an option is deployed, benefit-cost ratios are estimated for each program independently through-out the study period.
- Realistic Achievable Potential. In the realistic achievable cases, only cost-effective programs are considered. In addition, the integrated case accounts for participation in multiple programs and eliminates double counting. The study developed two levels of achievable potential.
  - Realistic Achievable Potential – Integrated Low Case. The low case uses input assumptions that have lower participation rates, lower penetrations of enabling technology, lower costs, and opt-in rate programs.
  - Realistic Achievable Potential – Integrated High Case. The high case uses input assumptions that have higher participation rates, higher penetrations of enabling technology, higher costs, and opt-out rate programs.

Key Considerations

The following list describes the key considerations which will provide context for the reader in reviewing the potential results:

- Estimates are incremental. Potential estimates, in all cases, are incremental to programs already implemented by utilities within the state of Michigan. When looking at overall potential, it is important to keep in mind that Michigan already has a significant amount of DR. The existing and forecasted capacity of programs is presented in Table 5-1. The existing capacity for each program type is shown in year 2017, and the forecasted capacity of each program is presented out to 2021. For our analysis, the forecast of existing capacity was held constant from 2021 through the end of the study period.
- Technical potential estimates are standalone. Technical potential estimates represent individual estimates for each program and do not account for double counting. These should be viewed as independent estimates of potential for each program regardless of participation in other programs, or cost effectiveness.
- Ancillary Services and Emergency Curtailment options do not appear in the realistic achievable cases. These two options are excluded because both programs are typically operated quite differently and at different times than a typical peak-shaving program. Therefore, these estimates are always incremental to that potential.
- Estimates are at the generator. Potential estimates are presented in terms of savings at the generator and account for line losses.

Table 5-1 Pre-existing Demand Response Capacity at the Generator

Program Type	2017	2018	2019	2020	2021
DLC	144	227	328	389	467
Curtailment Contracts	651	647	647	646	644
Capacity Bidding	56	111	167	167	166
Total Existing or Forecasted Capacity	**851**	**986**	**1,142**	**1,203**	**1,277**

Presentation of Results

For each potential case, technical achievable, realistic achievable high, and realistic achievable low, we will present the following:

- Total potential by program and segment in 2037. This table will allow the reader to quickly see which programs and which sectors contribute the most to the overall potential in the final year of the study.
- Potential by program over time. The chart and accompanying table present the total potential for each program option over the timeline for the study.
- Potential by segment over time. The cart and accompanying tables present the total potential coming from each customer segment over the timeline for the study.

High Level Potential Results

Before presenting the detailed results for each case, we present the overall results and point out some of our overarching observations.

Technical Achievable Potential

The analysis of individual DR options, which disregards cost-effectiveness and interactive effects, shows substantial savings from several options:

- In general, battery storage could be a game changer. We estimated a total potential of 806 MW in 2037 attributable to battery storage across the customer segments. Once batteries become cost effective, they could change the way customers use energy and how they respond to DR events.
- Variable peak pricing is a significant driver of potential in all cases, and in the high achievable case is the single largest program.

Realistic Achievable Potential

Below we present a comparison of the total estimated demand response potential for the two realistic achievable potential cases. In Table 5-2 and accompanying Figure 5-3 we show combined results across all programs. In Figure 5-3, we show saving by program in 2037.

Some observations regarding the overall potential results include the following:

- Total DR potential is 2.2 GW in the high achievable case. The key elements that are driving this potential are:
  - Battery storage is not cost effective and therefore not included in the low or high achievable cases.
  - As noted above, ancillary services and emergency curtailment are excluded from the low and high achievable cases.
- Total potential falls from 2.2 GW in the high achievable case to 1.3 GW in the low achievable case. The key elements driving this change are:
  - Overall reduction in participation rates across programs.
  - Moving from an opt-out / mandatory pricing scenario to a voluntary or opt-in pricing scenario.
- Variable peak pricing is a significant driver of potential in all cases, and in the high achievable case is the single largest contributor to potential.
- Direct load control is heavily weighted toward DLC of CAC using switches. This is a result of the current deployment of switch based DLC programs in the state, and the utility's prediction that switches will continue to be the control method of choice in the future. However, the analysis has shown that this was not the only successful technology.

Table 5-2 Overall Potential Results – Nominal and as a Percent of Baseline

Potential Case	2018	2019	2020	2023	2037
Potential Forecasts (MW)					
Realistic Achievable - High	849	1,179	1,706	2,017	2,214
Realistic Achievable - Low	265	520	991	1,255	1,339
Potential Savings (% of baseline)					
Realistic Achievable - High	3.8%	5.3%	7.7%	9.0%	9.7%
Realistic Achievable - Low	1.2%	2.3%	4.4%	5.6%	5.8%

Figure 5-2 Overall Realistic Achievable Potential Results Compared to Baseline

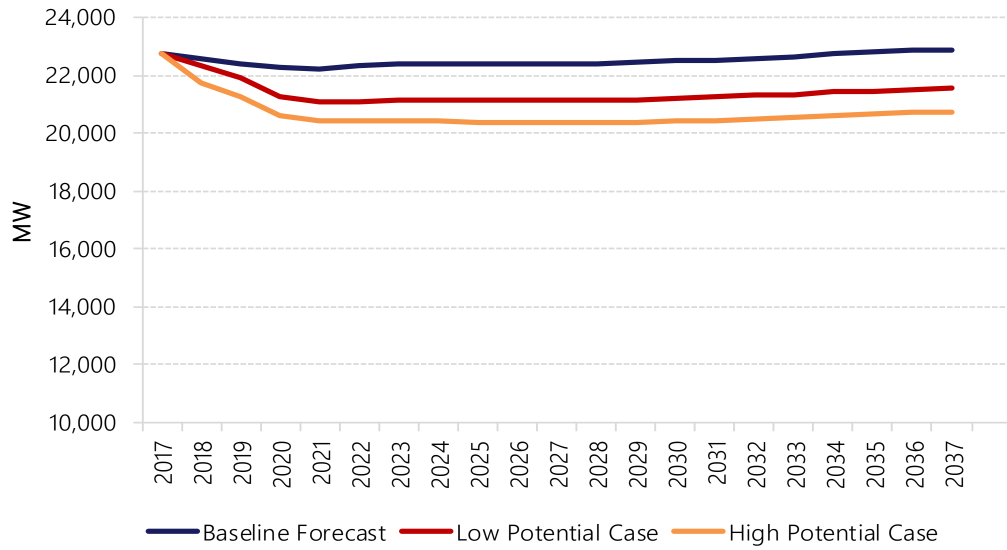
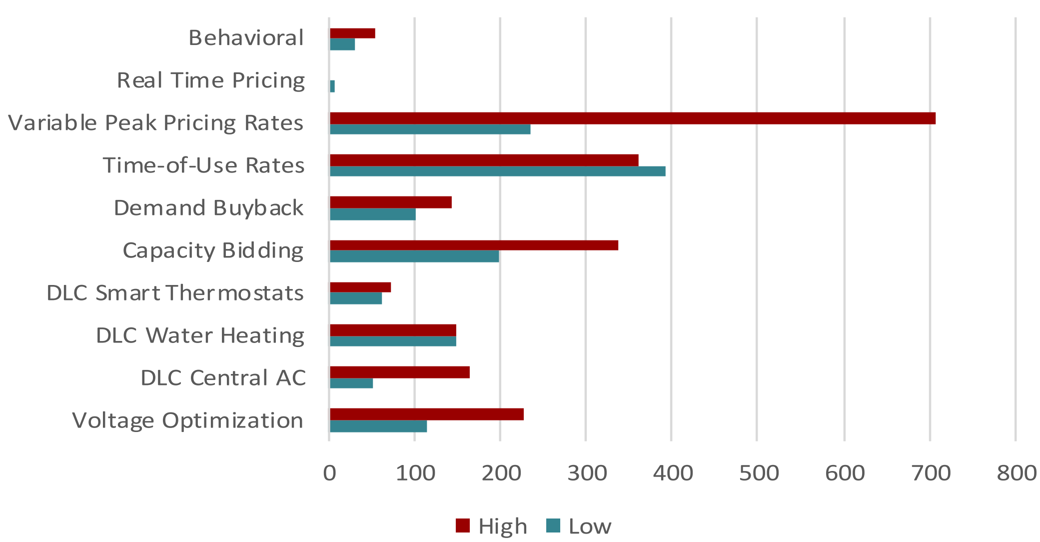


Figure 5-3 Overall Potential in the High and Low Cases by Program in 2037 (MW)



Some observations regarding the residential potential results include:

- The residential class is the largest contributor to potential in all cases and provides 50% to 60%of the total load reduction depending on the case.
- Dynamic pricing rates are the key mechanism for achieving potential in the residential class.

Some observations regarding the commercial and industrial potential results include:

- Small and medium C&I are the smallest contributors to overall potential in all cases. This is driven by lower participation rates and smaller impacts for these customer segments. This is expected and is supported by the interviews with implementers and secondary research.

- Large and extra-large C&I are the second largest contributors to overall potential behind residential, jointly contributing about 25% of the total potential reduction in the achievable case.
    - The largest impacts in these groups come from Capacity Bidding and Demand Buyback with the rate-based options being smaller contributors.
- Irrigation and water pumping customers were included in the analysis, but the potential reductions from these customers are relatively small. Irrigation load control was not cost effective, and their impacts on rate based programs tend to be more conservative.

Detailed Results – Technical Achievable Potential

Technical achievable potential represents an upper bound for potential DR attributable to each individual program without considering cost effectiveness. The individual potential estimates cannot be added together in the usual manner since the case does not account for double counting by enabling the program hierarchy. In this case, the "total potential" should be thought of as the total possible potential from each program, rather than as the total amount of DR available in the State of Michigan at one time. Table 5-3 shows the technical potential by program and segment in 2037.

Table 5-3 Technical Potential by Program and Segment as a Percent of Total in 2037

Program	Residential	Small C&I	Medium C&I	Large C&I	Extra Large C&I	Irrigation & Water Pumping
Voltage Optimization	102	35	23	25	29	12
Ancillary Services	106	19	12	13	15	3
DLC Central AC	613	23	-	-	-	-
DLC Water Heating	150	5	-	-	-	-
DLC Smart Thermostats	83	4	-	-	-	-
DLC Smart Appliances	47	-	-	-	-	-
Irrigation Load Control	-	-	-	-	-	58
Capacity Bidding	-	-	-	143	359	-
Emergency Curtailment	-	-	-	34	611	-
Demand Buyback	-	-	52	61	69	-
Time-of-Use Rates	344	2	20	37	32	12
Variable Peak Pricing Rates	646	59	123	48	54	12
Peak Time Rebates	18	1	-	-	-	-
Real Time Pricing	-	-	-	32	36	-
Thermal Energy Storage	-	22	14	19	21	-
Battery Energy Storage	360	126	84	91	103	42
Behavioral	71	-	-	-	-	-

Overall, residential has the highest technical potential amongst the six segments. Residential potential is concentrated in the Battery Storage and VPP programs. Amongst the C&I segments, extra-large C&I offers the highest level of technical potential with two programs, Capacity Bidding and Battery Energy Storage, providing the largest share. Irrigation and water pumping offered the lowest overall potential with irrigation load control offering less than half the potential of other large programs in different segments.

In Table 5-4 and accompanying Figure 5-4 we present the total technical potential in selected study years by program option. Overall, the two programs with the largest potential are Battery Storage and VPP.

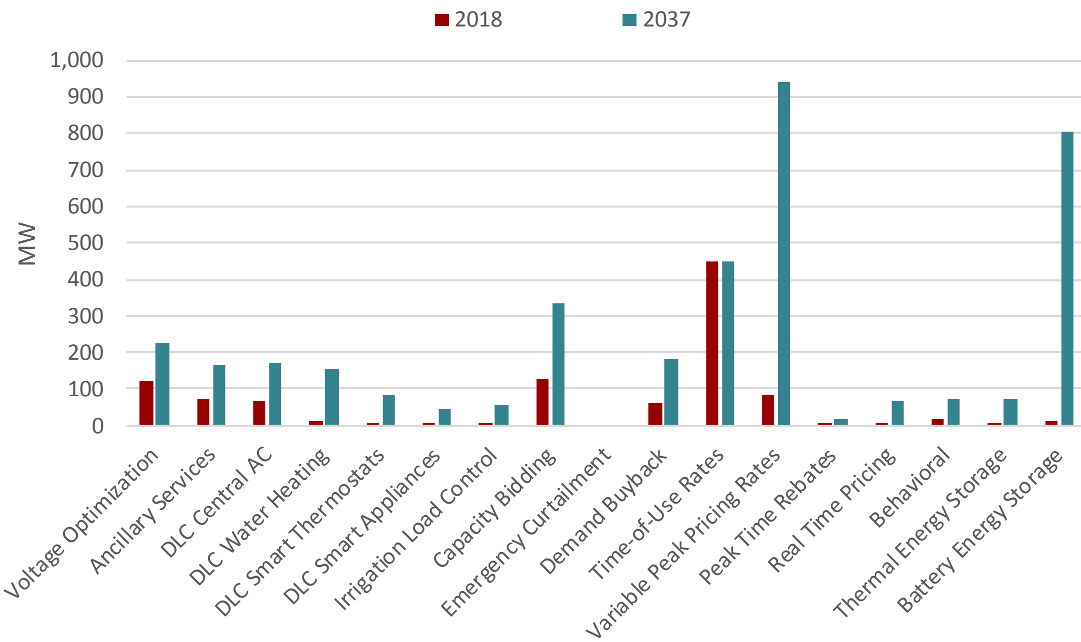
These two programs yield high levels of potential for largely opposite reasons: VPP has a lower amount of peak reduction but is widely applicable with higher participation rates, while Battery Storage has large reductions in demand but is harder to deploy widely due to capital costs and customer willingness to participate.

Note that Emergency Curtailment shows no incremental potential. We assumed that the Emergency Curtailment program would continue to exist in the state at its current size, but we did not forecast any additional incremental potential for this program in favor increased participation in other economic programs such as Capacity Bidding.

Table 5-4 Technical Potential Results by Program Option (MW)

Program	2018	2019	2020	2023	2037
Voltage Optimization	122	130	137	170	226
Ancillary Services	71	92	134	167	168
DLC Central AC	67	116	185	175	169
DLC Water Heating	15	46	108	157	156
DLC Smart Thermostats	9	26	61	87	86
DLC Smart Appliances	5	14	33	47	47
Irrigation Load Control	6	16	38	55	58
Capacity Bidding	129	219	265	312	336
Emergency Curtailment	-	-	-	-	-
Demand Buyback	61	86	134	172	181
Time-of-Use Rates	448	441	432	409	447
Variable Peak Pricing Rates	81	244	571	838	942
Peak Time Rebates	2	6	13	19	19
Real Time Pricing	6	19	45	65	68
Thermal Energy Storage	7	21	50	72	75
Battery Energy Storage	15	46	76	216	806
Behavioral	16	32	55	66	71

Figure 5-4 Technical Potential Results by Program Option in 2018 and 2037 (MW)



Economic Screening Results

Of the 17 programs which we considered in the analysis, 11 of them are economically feasible. The most notable programs that were not considered economically feasible are: Battery Storage, Ancillary Services, and DLC of Smart Appliances. However, nearly all the rate-based programs did pass the screen except for PTR, which did not result in enough MW savings to overcome its cost burden. Table 5-5 shows the levelized costs for each program, and the total MW achieved in year 2037. Cost effective programs are highlighted in green.

Table 5-5 Levelized Costs and Total Potential: Technical Achievable Case

Option	Upper MI	Lower MI	System Wtd Avg Levelized $/kW (2017-2037)	Total Potential MW in Year 2037
Voltage Optimization	$41.78	$41.78	$41.78	113.25
Ancillary Services	$484.46	$171.43	$176.34	114.61
DLC Central AC	$226.02	$75.91	$76.73	522.03
DLC Water Heating	$303.29	$107.85	$111.11	155.54
DLC Smart Thermostats	$197.88	$72.16	$72.87	70.30
DLC Smart Appliances	$1,365.53	$487.27	$501.04	31.23
Irrigation Load Control	$232.41	$76.54	$78.99	28.91
Capacity Bidding	$80.93	$80.93	$80.93	364.40
Emergency Curtailment		$47.00	$47.00	644.51
Demand Buyback	$22.30	$19.31	$19.35	119.52
Time-of-Use Rates	$41.09	$15.20	$15.55	466.76
Variable Peak Pricing Rates	$24.53	$9.43	$9.62	297.66
Peak Time Rebates	$336.57	$160.18	$162.91	46.13
Real Time Pricing	$5.74	$8.12	$8.08	33.97
Behavioral	$196.56	$69.42	$71.05	37.87
Thermal Energy Storage	$218.40	$212.43	$212.52	25.07
Battery Energy Storage	$776.87	$248.02	$256.31	402.81

Please note that only cost-effective programs will be included in the high and low achievable potential cases in the following sections.

Results – High Potential Case

The high potential case steps down the technical scenario in two ways: it institutes economic hurdles that programs must overcome before implementation, and the program hierarchy is enabled which eliminates double counting and allows for a traditional addition of the estimates across programs. It is also important to remember that the high case assumes an aggressive roll out of dynamic pricing, including opt-out TOU for residential and small and medium C&I, and mandatory TOU for large and extra-large C&I.

The results of the high potential case show a total potential of 2,214 MW in 2037. Table 5-6 shows the results of the high potential case. Recall from our list of key considerations that Emergency Curtailment and Ancillary Services were not included in the high or low potential.

Table 5-6 High Potential Results by Program and Segment in Year 2037

Program	Residential	Small C&I	Medium C&I	Large C&I	Extra-Large C&I	Irrigation & Water Pumping	Total
Voltage Optimization	5%	2%	1%	1%	1%	< 1%	**10%**
DLC Central AC	6%	1%	-	-	-	-	**7%**
DLC Water Heating	7%	-	-	-	-	-	**7%**
DLC Smart Thermostats	3%	< 1%	-	-	-	-	**3%**
Capacity Bidding	-	-	-	6%	9%	-	**15%**
Demand Buyback	-	-	2%	2%	2%	-	**7%**
Time-of-Use Rates	12%	-	< 1%	2%	1%	< 1%	**16%**
Variable Peak Pricing	22%	2%	4%	1%	1%	< 1%	**32%**
Real Time Pricing	-	-	-	-	-	-	**0%**
Behavioral	2%	-	-	-	-	-	**2%**
Total	**57%**	**5%**	**9%**	**13%**	**14%**	**2%**	**100%**

Again, we see that residential has the highest potential amongst the six segments contributing nearly 60% the total potential. In this case, residential potential is concentrated in the dynamic pricing programs with just over 60% of the residential potential coming from VPP and TOU. Amongst the C&I segments, extra-large C&I still offers the highest level of potential concentrated largely in the Capacity Bidding program. Again, irrigation and water pumping is the smallest, with small and medium C&I falling in the middle.

In Table 5-7 and accompanying Figure 5-5 we present the total high achievable potential in selected study years by program option. Overall, the two programs with the largest potential are VPP and TOU rates. These two programs yield high levels of potential because of the aggressive participation assumptions used in this case. The next largest contributor is Capacity Bidding, with the DLC and Demand Buyback programs following.

Table 5-7 High Potential Results by Program Option (MW)

Program	2018	2019	2020	2023	2037
Voltage Optimization	122	130	138	170	227
DLC Central AC	66	113	182	171	165
DLC Water Heating	15	45	105	149	148
DLC Smart Thermostats	8	23	52	73	73
Capacity Bidding	129	219	266	312	337
Demand Buyback	60	78	111	137	144
Time-of-Use Rates	417	392	362	330	361
Variable Peak Pricing Rates	73	206	448	626	708
Real Time Pricing	< 1	< 1	< 1	< 1	< 1
Behavioral	15	28	43	49	53
Achievable Potential (MW)	**904**	**1,235**	**1,706**	**2,017**	**2,214**

Figure 5-5 High Potential Results by Program Option (MW)

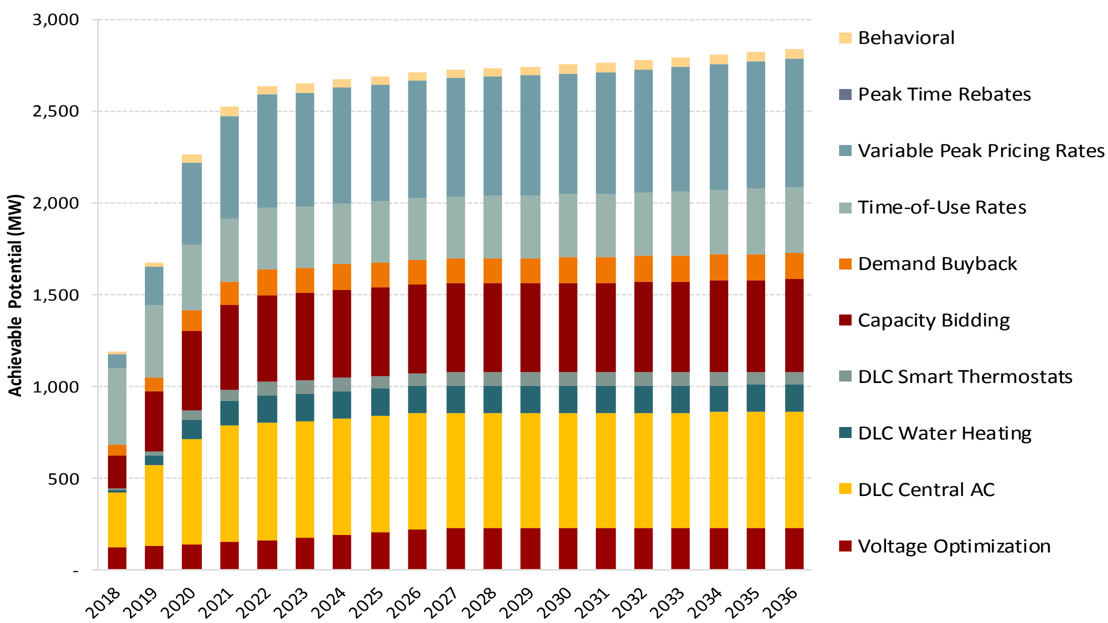
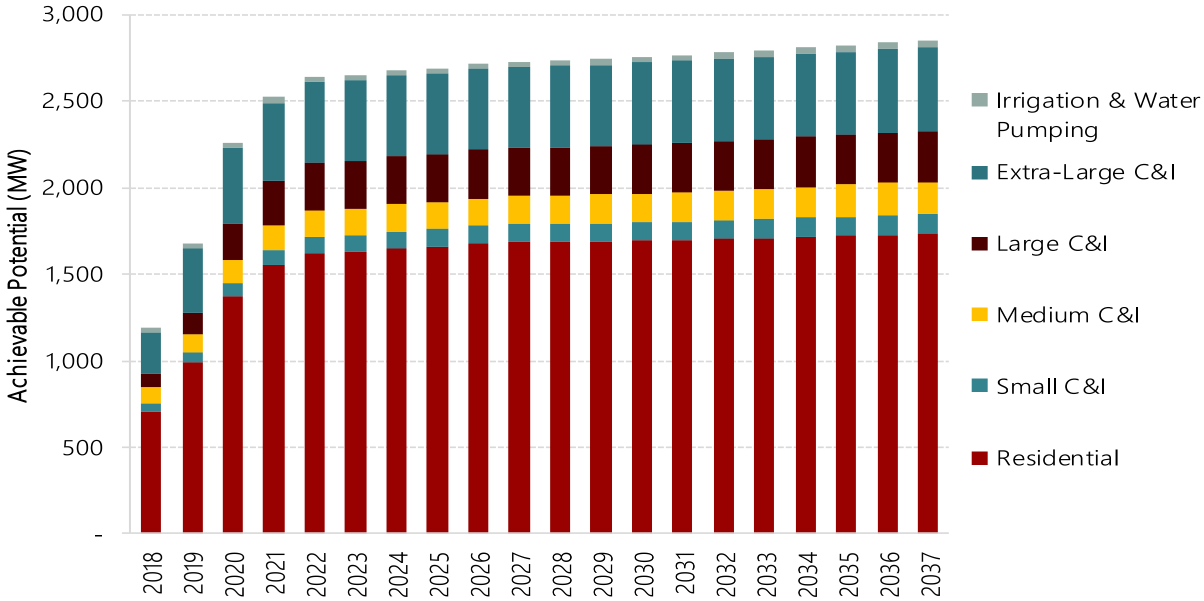


Table 5-8 and accompanying Figure 5-6 show the forecast for selected years by segment. Keep in mind that these impacts are incremental over the existing utility program offerings and assume that those programs remain in place through the end of the study.

Table 5-8 High Potential Results by Customer Segment (MW)

Customer Segment	2018	2019	2020	2023	2037
Residential	481	663	982	1,163	1,263
Small C&I	40	52	77	98	115
Medium C&I	96	108	132	155	188
Large C&I	83	129	213	276	290
Extra-Large C&I	126	202	274	297	321
Irrigation & Water Pumping	23	25	28	29	36
Total	**849**	**1,179**	**1,706**	**2,017**	**2,214**

Figure 5-6 High Potential Results by Customer Segment (MW)



Results – Low Potential Case

The low potential case steps down the high potential scenario by reducing customers' willingness to participate and moving to opt-in scenarios (vs. opt-out) for dynamic pricing. The other limits from the high potential case remain the same: the program must be economically viable over its expected lifetime and interactions between programs remain.

Lower program adoption rates result in a total potential of 1,339 MW vs. 2,214 MW in the high potential case – a difference of 875 MW or 3.8% of total peak load in 2037. Variable Peak Pricing sees the largest reduction as the number of customers estimated to be willing to participate in this program is much lower in this scenario. Table 5-9 summarizes the total impact by segment and program for 2037 in the low potential case.

Table 5-9 Low Potential Results by Program and Segment in Year 2037

Program	Residential	Small C&I	Medium C&I	Large C&I	Extra-Large C&I	Irrigation & Water Pumping	Total
Voltage Optimization	4%	1%	< 1%	< 1%	1%	< 1%	**8%**
DLC Central AC	3%	1%	-	-	-	-	**4%**
DLC Water Heating	11%	-	-	-	-	-	**11%**
DLC Smart Thermostats	4%	< 1%	-	-	-	-	**5%**
Capacity Bidding	-	-	-	7%	8%	-	**15%**
Demand Buyback	-	-	3%	3%	2%	-	**8%**
Time-of-Use Rates	20%	-	< 1%	4%	4%	< 1%	**29%**
Variable Peak Pricing	7%	2%	4%	2%	2%	< 1%	**18%**
Real Time Pricing	-	-	-	< 1%	< 1%	-	**< 1%**
Behavioral	2%	-	-	-	-	-	**2%**
Total	**51%**	**5%**	**9%**	**16%**	**17%**	**1%**	**100%**

Even in the low case, residential has the highest potential of the six segments, contributing just about half of the total potential. Residential potential is still concentrated in the dynamic pricing programs with just over half of the residential potential coming from VPP and TOU, although, TOU carries the larger share of the potential in this case. Among the C&I segments, extra-large C&I still offers the highest level of potential, although the disparity between segments is less severe in this case. Again, irrigation and water pumping is the smallest, contributing a mere 15 MW to the total potential.

In Table 5-10 and accompanying Figure 5-7 we present the total low achievable potential in selected study years by program option. Overall, the two programs with the largest potential are still VPP and TOU although TOU impacts are larger than VPP impacts in this case. The next largest contributor is Capacity Bidding, with the DLC and Demand Buyback programs following.

Table 5-10 Low Potential Results by Program Option (MW)

	2018	2019	2020	2023	2037
Voltage Optimization	64	74	95	111	113
DLC Central AC	26	34	80	57	52
DLC Water Heating	15	45	105	149	148
DLC Smart Thermostats	7	19	44	62	61
Capacity Bidding	26	77	149	181	198
Demand Buyback	54	69	88	97	102
Time-of-Use Rates	40	116	258	363	392
Variable Peak Pricing Rates	22	64	140	201	235
Real Time Pricing	3	6	9	7	7
Behavioral	8	15	24	27	29
Total Achievable Potential (MW)	**265**	**520**	**991**	**1,255**	**1,339**

Figure 5-7 Low Potential Results by Program Option (MW)

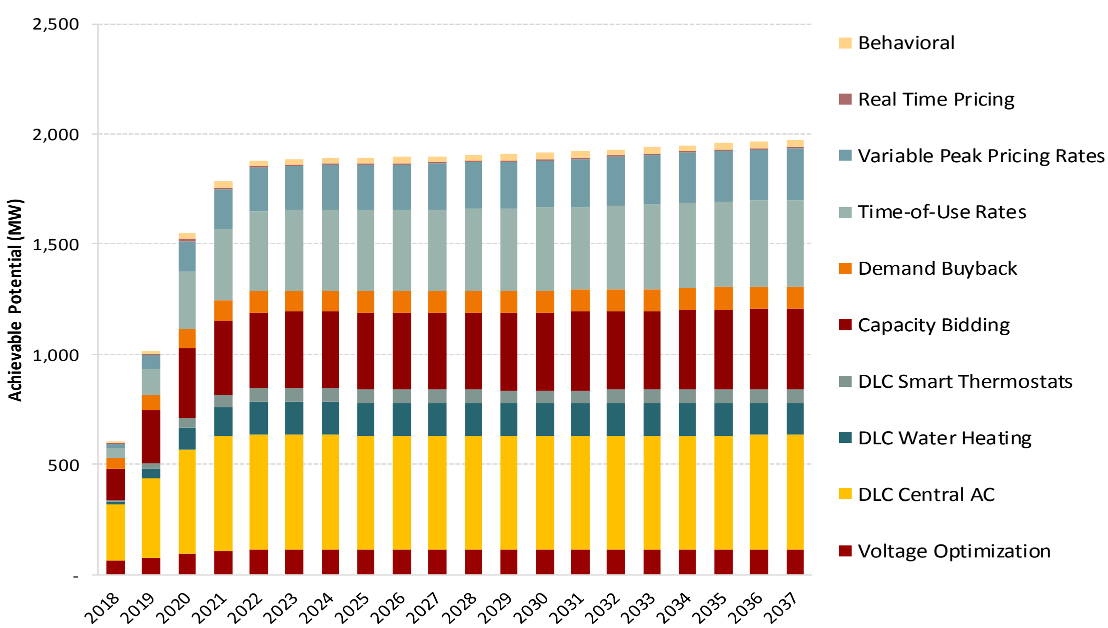
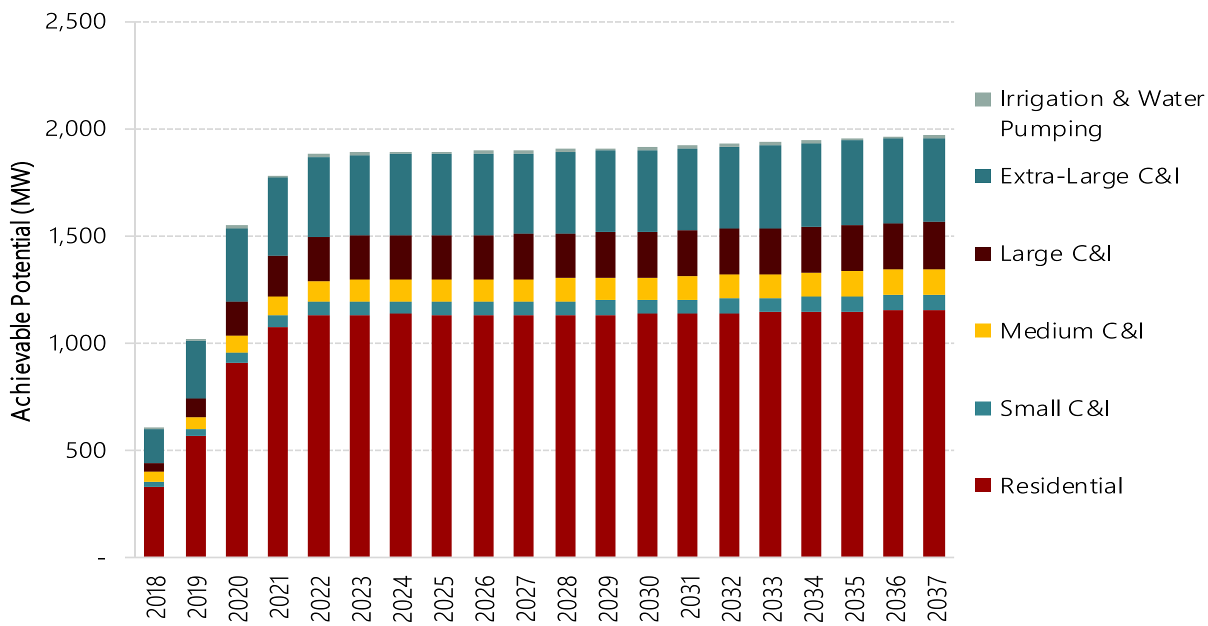


Table 5-11 and Figure 5-8 show the potential results for selected years by customer segment. Compared to the high scenario, residential again shows the biggest drop in potential. This comes from the large reduction in the adoption of VPP. Overall, this gives a total market potential for the state of Michigan of 1,339 MW or 6% of load.

Table 5-11 Low Potential Results by Customer Segment (MW)

Customer Segment	2018	2019	2020	2023	2037
Residential	98	235	518	666	686
Small C&I	21	30	46	61	71
Medium C&I	52	62	80	98	119
Large C&I	39	82	157	209	220
Extra-Large C&I	48	104	179	208	227
Irrigation & Water Pumping	6	7	10	12	15
Total	**265**	**520**	**991**	**1,255**	**1,339**

Figure 5-8 Low Potential Results by Customer Segment(MW)



6

RECOMMENDATIONS

In this section, we present two sets of recommendations based on the analysis performed in this study. First, we present our recommendations related to demand response program in general as they relate to the potential. Second, we present our recommendations for the next round of analysis which largely consist of items that we could not address as part of this study due to time constraints.

Program Implementation Recommendations

While utilities within the state of Michigan currently have excess capacity, conditions are expected to change within the next five to ten years. By as early as 2023, the state expects that utilities will need to acquire new capacity and, at that time, demand response could play a major role in filling those needs.[15] We identified many DR options as part of this study, but our results point to several with the most potential for meeting future capacity requirements including:

- Dynamic pricing options, particularly for residential customers,
- Capacity Bidding and Demand Buyback in the large and extra-large C&I customer segments
- And Battery Storage.

More specific recommendations regarding notable DR programs and their potential implementation follow:

Battery Storage

While Battery Storage was not found to be cost effective in the context of this study, the potential for this option is huge. As we learn more about Battery Storage, and as costs continue to decline in future years, Battery Storage could become a very real, and very valuable resource for utilities. Several interviews in the extra-large customer segment expressed interest in Battery Storage, and some even mentioned plans to purchase them in the near future.

We recommend that utilities consider conducting pilot programs and/or targeted studies on Battery Storage to be able to lead the industry in the integration Battery Storage with the grid in a mutually beneficial manner. This may include special rates, programs, rules, and/or education.

- With solar DG, many utilities found themselves behind the curve, and have been racing to catch up with the appropriate rate structures and compensation. Up front research could avoid a similar situation with batteries.

Dynamic Pricing Programs

Our results show that dynamic pricing programs have the potential to be the single largest contributor to future DR resources. However, it is important to note that not all programs (or implementation strategies)

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[15] Michigan Capacity Resource Assessment from January 2017, conducted by the Michigan Agency for Energy and MPSC; http://www.michigan.gov/documents/energy/Michigan_EGEAS_Report__01_31_2017_550217_7.pdf

are created equal. For example, it is possible to obtain higher impacts through a properly deployed voluntary program with a strong price signal than through an opt-out or mandatory program.

We recommend that utilities consider a variable VPP over a TOU or PTR program, particularly for residential customers.

- VPP impacts tend to be much higher than TOU impacts. VPP impacts generally exceed 15% and can go up to 40% with the appropriate enabling technology, while TOU impacts range from five to seven percent in most territories. Even in an opt-out scenario, the VPP are so much larger that they outshine the impacts from opt-out TOU. Finally, because VPP is event based and TOU is not, VPP is clearly a stronger option for achieving demand response savings. In addition, the existing AMI infrastructure within the State provides Michigan with a head start on implementing these types of programs.
- While PTR, with its win-win philosophy, seems like a great idea, in practice the impacts from PTR are small. Even with enabling technology, the impacts from PTR still tend to be lower than VPP. In addition, VPP avoids the hassle of calculating customer-specific baselines in favor of clearly communicated price signals.

We recommend that utilities also consider VPP and RTP as options for medium to extra-large C&I customers even if the broader nationwide regulatory environment seems to be pushing toward mandatory TOU rates for these customers.

- Some large customers actually want the additional opportunity to save money that the stronger price signals provide, therefore VPP and RTP are still viable options which provide more DR than TOU alone.

DLC Programs

The utilities are currently heavily focused on switch-based control on central AC units. Our analysis identified a couple of additional good candidates for incremental DLC potential, and some poor candidates for additional potential.

We recommend that utilities also consider smart thermostats for DLC particularly in the residential sector. They can function like a traditional switch or can be used to enable participation in dynamic pricing and can interact with other smart appliances.

We recommend that utilities consider DLC of water heating. It is relatively untapped in the region, and showed a significant amount of incremental potential.

We do not recommend pursuing an irrigation load control program at this time. The desire and potential for DR programs targeted to irrigation and water pumping customers is small. In addition, based on PSC research, the types of irrigation that Michigan farming customers would do during peak times is non-discretionary.

Successful DR Programs in General

Through our work in the DR space, we have found that successful DR programs have several things in common: internal commitment, education, operations, and enabling technology.

We recommend that utilities provide, or otherwise incentivize, enabling technology whenever it is cost effective to do so. Enabling technology is extremely important in maximizing impacts from residential programs and helping to improve impacts and participation for commercial customers.

- For residential customers, we see significant increases in impacts from dynamic pricing programs. Savings increase from approximately 15% without enabling technology to 30% or more with technology.

- Particularly for SMB customers, automation is required to participate effectively in most programs.

We recommend that utilities focus on educating all types of customers on different program options to help customers choose the best option for them and ensure that they understand how to reduce load once they are on a program.

- In the interviews, we saw that C&I customers often stated that curtailment options were their first choice, however they were receptive to other programs as well, once they understood them.
- Residential customers have shown that they can respond to price signals that change daily, as long as they understand the program and how to respond.

We recommend that utilities are clear about how they intend to operate programs. We have found that clearly establishing expectations with customers eliminates many issues with customer satisfaction.

Analysis Recommendations

Below we present several recommendations for improving or enhancing future analyses of DR potential in the state.

- Segment customers between single family and multi-family for select residential demand response and rate options. Michigan PUC staff expressed interest in seeing what potential there was within in the multi-family segment. However, due to time constraints, AEG was unable to conduct secondary search on the multi-family segment and incorporate that data into the study.
- Explore a sensitivity around DLC of space cooling with switch and smart-thermostat participation. After interviewing utilities, a focus on DLC with switches rather than smart thermostats were highlighted. This trend was reflected in this study; However, evidence exists in other states and programs that there is a market shift towards using smart thermostats for DLC. With possible primary research to support, modeling a sensitivity with increased smart thermostat DLC participation would provide insight into possible potential if Michigan utilities embraced this shift.
- Explore sensitivity with varied DLC incentive structures. Currently, utilities in Michigan are implementing differing incentive structures. AEG modeled what is most frequently encountered in the industry, an annual $25 incentive payment. Due to time constraints, AEG was unable to model potential with a different incentive structure, such as a monthly dollar per kWh or kW incentive or fixed monthly incentive in addition to, or instead of, the annual incentive.
- Examine an "aggressive" AMI roll out scenario. AEG utilized anecdotal information from the utility interviews and secondary data from EIA to establish current/expected AMI deployment within the state. AEG and MPUC were interested in a scenario that modeled a more extensive roll out to all customers.
- Consider separate feasibility studies for voltage optimization and/or battery storage if enough interest exists. These two options incorporate costs and benefits that are beyond the scope of demand response. While we included these options as programs within the study, each includes complex technologies that require more detailed information and modeling to encompass all the benefits to establish cost effectiveness on a larger scale.

A

APPENDIX A – RESOURCES AND REFERENCES

Several of our secondary sources include but are not limited to:

- Oracle presentation to AEG on Behavioral DR in Michigan. 8/30/17
- "Review and Validation of 2015 Pacific Gas and Electric Home Energy Reports Program Impacts (Final Report)" DNVGL, CPUC CALMAC Study, 5/5/2017
- "Xcel Energy Colorado Smart Thermostat Pilot – Evaluation Report", Nexant, Xcel Energy Colorado, 5/12/17
- "Direct Load Control of Residential Air Conditioners in Texas", Brattle Group, Public Utility Commission in Texas, 10/25/12
- Ghatikar, Rish. Demand Response Automation in Appliance and Equipment. Lawrence Berkley National Laboratory, 2015.
- 2015 ISACA IT Risk Reward Barometer - US Consumer Results. October 2015.
- SCE Agriculture DR Potential - Final Report, Global Energy Partners. 4/31/11
- Entergy Arkansas 2016 Agricultural Irrigation Load Control Program Manual. 1/12/16
- "Smart Currents Dynamic Peak Pilot Final Evaluation Report", DTE Energy. 8/15/14
- "Economic Potential for Peak Demand Reduction in Michigan", Demand Side Analytics, Optimal Energy. Advanced Energy Economy Institute. 2/16/17
- "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory", Brattle Group, Xcel Energy Northern States, April 2014
- "2015 Impact Evaluation of San Diego Gas & Electric's Residential Peak Time Rebate and Small Customer Technology Deployment Programs", Itron, SDG&E
- Lazard's Levelized Cost of Storage – Version 2.0, December 2016
- "Federal Tax Incentives for Battery Storage Systems", NREL, NREL/FS-7A40-67558. January 2017.
- "Appendix L. Cost functions for thermal energy storage in commercial buildings", Renewable Electricity Futures Study: Volume 3 End-use Electricity Demand. NREL. Global CCS Institute. 2012.
- "Thermal Energy Storage: Technology Brief", International Renewable Energy Agency. IEA-ETSAP and IRENA© Technology Brief E17 – January 2013
- DiOrio, Nicholas, Aron Dobos, and Steven Janzou. "Economic Analysis Case Studies of Battery Energy Storage with SAM", NREL. NREL/TP-6A20-64987 November 2015
- Consumers Energy Company Rate Book for Electricity Service. M.P.S.C. No. 13 – Electric. https://www.consumersenergy.com/~/media/ce/documents/rates/electric-rate-book.pdf
- "2014 SCE PTR Load Impact Evaluation", Nexant. April 1, 2015.

- "Major Findings from a DOE-Sponsored National Assessment of Conservation Voltage Reduction (CVR). IEEE Volt-Var Task Force Panel Session. Applied Energy Group. July 29, 2015
- Voltage Optimization Feasibility Study, Smart Grid Advanced Metering Annual Implementation Progress Report: Appendix A - Reports. Applied Energy Group. Commonwealth Edison Company. December 2014.
- Annual Energy Outlook 2017, U.S. Energy Information Administration. January 5, 2017.
- EIA-861 Form Data, U.S. Energy Information Administration. August 14, 2017.
- DR, EE, DG Potential Assessment for Midcontinent ISO. Applied Energy Group. December 2015.
- PacifiCorp Demand-side Resource Potential Assessment for 2017-2036. Applied Energy Group. February 3, 2017

Specifically, these sources were used to supplement:

- Program costs, impacts, and lifetimes
- Market willingness to adopt programs
- AMI meter saturation
- Avoided cost escalation factors

B

APPENDIX B – SURVEY INSTRUMENTS

State of Michigan Residential Demand Response Market Potential Questionnaire

QUALIFYING CRITERIA AND QUOTAS

Qualifying Criteria

- The respondent must have primary or shared responsibility for making energy-related decisions
- The respondent must be at least 18 years old
- The respondent must be served by a Michigan utility

Hard Quotas

Total: n=400

Soft quotas:

Details TBD, but are expected to include age, gender, geography, housing type, education

Goal will be to ensure that respondent demographics are as close as possible to current population proportions

RESPONDENT IDENTIFICATION / VERIFICATION

Welcome. This survey is sponsored by the Michigan Public Service Commission (MPSC) and Michigan Agency for Energy (MAE)

Survey results will be collected and summarized by SHC Universal, a market research company contracted by MPSC/MAE to collect and analyze these results.

We at MPSC/MAE and SHC Universal value your privacy. We will use the information you provide for research purposes only and will NOT share it with third parties for marketing purposes. Information you provide will be stored in a secure database. If you have any questions about the legitimacy of this research, please contact SHC Universal.

INTRODUCTION

Thank you for taking the time to see if you and your household qualify to participate in a new research study about electricity use. The study is sponsored by the Michigan Public Service Commission, and it has a very important purpose. As part of Michigan's new energy plan that was signed in December 2016, Public Act 341 directs the MPSC to conduct a statewide study to determine the potential to save energy with new customer programs. Your answers to this survey will help the MPSC to maximize the potential benefits to ratepayers that may occur as a result of these new programs.

You will first be asked a few questions to make sure your household qualifies to complete the full survey, then if you qualify, you can move on to the full survey.

> *Note: If you need to pause the survey at any time, you can come back later to where you left off. Simply save the URL and the Survey ID# from your survey invitation to access your survey again. The survey will automatically take you to the point where you left off.*

Please note: Any word or phrase that appears in blue, underlined font will have a pop-up box with definition when you mouse-over that word or phrase.

Please click "Next" to begin.

Survey Qualification Questions

S1. Which of the following categories represents your current age?

1. Less than 18 years old [TERMINATE AFTER S9]
2. 18-24
3. 25-34
4. 35-44
5. 45-54
6. 55-64
7. 65 or more years old

S1a. In which state is your primary residence located?
[DROP DOWN LIST OF 50 STATES]
[TERMINATE AFTER S9 IF S1A DOES NOT EQUAL MICHIGAN]

S2. Do you, or does anyone else in your household, work for a gas or electric utility company?

1. Yes [TERMINATE AFTER S9]
2. No

S3. What is your role in making electricity-related decisions for things like choosing settings for your home's thermostat or selecting new appliances for your home?

1. You are primarily responsible for some or all of these decisions
2. Someone else in your household is primarily responsible for these types of decisions [TERMINATE AFTER S9]
3. Someone else such as a landlord or property manager is primarily responsible for these types of decisions [TERMINATE AFTER S9]
4. You share responsibility for these decisions with someone else
5. Don't know [TERMINATE AFTER S9]

S4. What is the name of the electricity provider that serves your primary residence? [INCLUDE AS DROP DOWN MENU]

1. Alger Delta Cooperative
2. Alpena Power Company
3. Bayfield Electric Cooperative
4. Cherryland Electric Cooperative
5. Cloverland Electric Cooperative
6. Consumers Energy
7. DTE Electric Company (Detroit Edison Electric Company)
8. Great Lakes Energy Cooperative
9. Indiana Michigan Power Company (I&M)
10. Lansing Board of Water & Light
11. Midwest Energy Cooperative
12. Ontonagon County REA
13. Presque Isle Electric and Gas Co-op
14. Thumb Electric Cooperative

15. Tri-County Electric Cooperative
16. Upper Peninsula Power Company (UPPCO)
17. Upper Michigan Energy Resources (UMERC)
18. Wisconsin Electric Power Company (We Energies)
19. Wisconsin Public Service Corporation
20. Wolverine Power Supply Cooperative
21. Xcel Energy (Northern States Power)
22. Another electricity provider [PLEASE SPECIFY]
99. Don't Know [TERMINATE AFTER S9]

S5. What is your gender?
1. Male
2. Female

S6. What is the highest level of education you have completed?
1. Less than a high school degree
2. High school degree
3. Technical/trade school program
4. Associates degree or some college
5. Bachelor's degree
6. Graduate / professional degree, e.g., J.D., MBA, MD, etc.
7. Professional certification, e.g., CPA, CNP, etc.

S7. What is your current work status?
1. Employed full-time
2. Employed part-time
3. Not currently employed
4. Retired
990. Other [SPECIFY]

S8. Where is your primary residence located?
1. Southeast Michigan (Metro Detroit)
2. Northeast Michigan or the Thumb (the area around Flint, Saginaw, and Port Huron)
3. West Michigan (the area around Kalamazoo, Grand Rapids, Muskegon)
4. The Northern Lower Peninsula (the area north of Mt. Pleasant)
6. Mid-Michigan (the area around Jackson, Lansing, and Mt. Pleasant)
5. The Upper Peninsula of Michigan
990. Another part of Michigan [PLEASE SPECIFY]
991. Outside of Michigan [TERMINATE AFTER S9]

S9. Which of the following best describes your home?
1. Single-family home
2. Duplex/Townhome
3. Multi-family house or building with 3-4 apartments/condominium units
4. Multi-family house or building with 5 or more apartments/condominium units
5. Manufactured home
6. Mobile home
98. Other **[PLEASE SPECIFY]**

[PROGRAMMER NOTE: TERMINATE HERE IF S1=1, OR S1A NE Michigan, S2=1, OR S3=2, 3, OR 5, or S4=99 or S8=991]

TERMINATE LANGUAGE FOR NON-QUALIFYING OR OVER-QUOTA RESPONDENTS

We truly appreciate your time and effort in responding to our survey invitation and answering these initial questions, which were designed to see if you are eligible to participate.

In order to achieve a representative sample, we had to define specific criteria for survey respondents. At this time, we have reached the number of respondents we can accept from individuals with your type of experience or background. Again, we would like to thank you for your time and effort.

Thank you. Have a nice day!

INVITATION LANGUAGE FOR QUALIFYING RESPONDENTS

Thank you for your responses so far! You qualify for the survey. We appreciate your time in filling out the survey as completely as possible.

As we indicated earlier, only a limited number of individuals are being asked to complete this survey, so we appreciate your time in filling out the survey as completely as possible. It should take about 15-20 minutes to complete the questions.

Your responses are important to us, so please press “Next” to begin answering the survey questions. All information provided in this survey will be kept strictly confidential, and at no time will you be asked to purchase anything.

If you need to pause the survey at any time, you can come back later and begin again where you left off. Simply save the personalized URL to access your survey again. The survey will automatically take you to the point where you left off.

As you complete the survey, you will not be able to use your browser’s “back” button. If you mistakenly press your browser’s “back” button, you will need to press the “refresh” button to continue the survey.

HOUSEHOLD INFORMATION

Q1. Including yourself, how many individuals normally live in your home? Do not include anyone who is just visiting, those away in the military, or children who are away at college.

[RECORD NUMBER 1-20] individuals

Q3. Do you own or rent your home?
1. Own (or in the process of buying it)
2. Rent / lease

Q4. In about what year was your home built?
1. Before 1965
2. 1965-1974
3. 1975-1984
4. 1985-1994
5. 1995-2004
6. 2005-2010
7. 2010-2015
8. 2016-present
97. Not sure

Q5. What is the approximate square footage of your home? <u>Please include only heated living space in your response.</u>
If you are not certain, please give your best estimate.
1. Less than 500 sq. ft.
2. 500 – 999
3. 1,000 – 1,499
4. 1,500 – 1,999
5. 2,000 – 2,499
6. 2,500 – 2,999
7. 3,000 – 3,499
8. 3,500 – 3,999
9. 4,000 sq. ft. or more

Q6 How many bedrooms are there in your home and at your property? Please include any heated rooms that are regularly used as bedrooms, including those located in the basement, attic, or in an outbuilding.
0. 0 / Studio/Efficiency apartment / SRO (single-room occupancy)
1. 1
2. 2
3. 3
4. 4
5. 5
6. 6 or more

Q7. How many bathrooms are in your home? (*Please consider a bathroom that does not include either a bathtub or shower as a half-bathroom.)*

a) Full bathrooms ______

b) Half bathrooms _______

Q8. Is your property occupied all year (perhaps excluding vacations), or is it occupied for only part of the year (as a seasonal, or vacation property)?
1. Occupied all year
2. Occupied for most of the year
3. Occupied for only a part of the year

HEATING AND COOLING

PROGRAMMER NOTE: THROUGHOUT THIS SURVEY, WORDS OR PHRASES WITH BLUE, UNDERLINED FONT WILL SHOW POP-UP BOX WHEN THE RESPONDENT MOUSES OVER THE WORD OR PHRASE. HYPERLINKED DEFINITIONS ARE PROVIDED AT THE END OF THIS DOCUMENT.

Q9. Which of the following systems/equipment do you use to cool your property, even if only once in a while, and / or for only part of your property? *Select all that apply.*

01. Central air conditioner
02. One or more room air conditioners
03. Air-source heat pump
04. Geothermal heat pump
05. Whole-house fan or attic fan
06. One or more portable dehumidifiers
07. One or more ceiling fans
08. One or more window or room fans
97. Other [SPECIFY]
98. Not sure [EXCLUSIVE]
00. My home has no cooling systems/equipment [EXCLUSIVE]

PROGRAMMER NOTE: IF MORE THAN 1 ITEM SELECTED IN Q9, DISPLAY Q10, BUT ONLY DISPLAY ITEMS SELECTED IN Q9; OTHERWISE AUTOCODE Q10=Q9 AND SKIP TO INSTRUCTION BEFORE Q11.

Q10. Which one of these cooling systems/equipment do you use most often, or to cool most of your property?
[ONLY DISPLAY ITEMS SELECTED IN Q9]

01. Central air conditioner
02. One or more room air conditioners
03. Air-source heat pump
04. Geothermal heat pump
05. Whole-house fan or attic fan
06. One or more portable dehumidifiers
07. One or more ceiling fans
08. One or more window or room fans

97. Other [PLEASE SPECIFY]
98. Not sure [EXCLUSIVE]

Q11. Which of the following systems/equipment do you use to heat your property, even if only once in a while, and / or for part of your residence? *Select all that apply.*
01. Central warm air furnace with ducts/vents to individual rooms
02. Central boiler with hot water/steam radiators or baseboards in individual rooms
03. Electric baseboard or electric coils radiant heating
04. An air-source heat pump
05. A geothermal heat pump
06. One or more wall furnaces
07. One or more fireplaces
08. One or more wood burning stoves
09. One or more wall-mounted space heaters
10. One or more portable space heaters
97. Other [SPECIFY]
98. Not sure [EXCLUSIVE]
00. My home has no heating systems/equipment [EXCLUSIVE]

PROGRAMMER NOTE: IF MORE THAN ONE ITEM SELECTED IN Q11, DISPLAY Q12, BUT ONLY DISPLAY ITEMS SELECTED IN Q11; OTHERWISE AUTOCODE Q12=Q11 AND SKIP TO Q13.

Q12. Which <u>one</u> of these heating systems/equipment do you use to heat the largest portion of your residence?
[ONLY DISPLAY ITEMS SELECTED IN S8]
01. Central warm air furnace with ducts/vents to individual rooms
02. Central boiler with hot water/steam radiators or baseboards in individual rooms
03. Electric baseboard or electric coils radiant heating
04. An air-source heat pump
05. A geothermal heat pump
06. One or more wall furnaces
07. One or more fireplaces
08. One or more wood burning stoves
09. One or more wall-mounted space heaters
10. One or more portable space heaters
97. [INSERT S8_990 RESPONSE]
98. Not sure [EXCLUSIVE]
00. My home has no heating system/equipment that heat all of most of my home [EXCLUSIVE]

Q13. What is the primary fuel that is used by your home's primary heating system?
1. Electricity
2. Natural gas

3. Propane or LP gas
4. Wood or pellets
5. Other [PLEASE SPECIFY]
98. Not sure

Q14. Using a 10-point scale where '1' means you strongly disagree, and '10' means you strongly agree, please indicate how much your household agrees or disagrees with each of the following statements about your electricity service provider.
Note: If you don't feel like you are very familiar with your electricity provider on any of the following items, please just provide your best estimate.
My electricity provider is…

[PROGRAMMER: ROTATE OPTIONS]	1	2	3	4	5	6	7	8	9	10
1. …a credible information source for the community on energy efficiency	○	○	○	○	○	○	○	○	○	○
2. …a company that actively promotes programs to help its customers save money	○	○	○	○	○	○	○	○	○	○

Q15. Overall, how satisfied would you say your household is with the service you receive from your electricity service provider?

Not at all satisfied								Extremely satisfied	
1	2	3	4	5	6	7	8	9	10
○	○	○	○	○	○	○	○	○	○

Q16. We would like to understand how your household as a whole thinks about using electricity. Using a 10-point scale where '1' means you strongly disagree, and '10' means you strongly agree, please indicate how much you agree or disagree with each of the following statements.

[RANDOMIZE LIST ITEMS]	Strongly disagree									Strongly agree
	1	2	3	4	5	6	7	8	9	10
1. Comfort is very important to your household – even if it means spending more each month for electricity	○	○	○	○	○	○	○	○	○	○
2. Realistically, there isn't much you can do to save money on electricity costs	○	○	○	○	○	○	○	○	○	○
3. Conserving electricity at your home will make no difference to the quality of the environment overall	○	○	○	○	○	○	○	○	○	○
4. The threat from global warming is real, and significant	○	○	○	○	○	○	○	○	○	○
5. You are an "early adopter" of new home technologies	○	○	○	○	○	○	○	○	○	○

Q17. **Does your home use one or more thermostats to control your heating and/or cooling system(s)? (Please select all that apply.)**

1. Yes, a programmable thermostat (one that lets you program a schedule and set the temperature up or down at different times of the day and/or different days of the week)
2. Yes, a basic smart thermostat (similar to a programmable thermostat, but it has Wi-Fi capability for programming and adjusting thermostat settings remotely.)
3. Yes, a learning smart thermostat (similar to the basic smart thermostat, but it also has the capability to "learn" household preferences and adjust thermostat settings accordingly. An example is the Nest thermostat.)
4. Yes, a standard/manual thermostat (one with a single setting for the internal temperature which you manually adjust)
5. No thermostat (exclusive)

****PROGRAMMER NOTE: IF Q17=1 -3, CONTINUE, OTHERWISE SKIP TO Q20.****

Q18. **Does your programmable thermostat actually operate in a programmed mode for most of the year?**

1. It is not programmed; we use it like a traditional thermostat
2. We occasionally run programmed settings
3. We always run programmed settings
4. Not sure

Q19. **Are you able to communicate with your thermostat over the internet (using a smartphone, tablet, or other type of computer)?**

1. Yes, and we use this feature
2. Yes, but we do not use this feature
3. No

Q20. What type of water heating system do you use in your home? *If you use more than one water heating system, answer for the system that is used most often.*

1. Standard tank
2. Heat pump water heater
3. Instantaneous / tankless system
4. Solar water heating system (not Photovoltaic)
5. Something else **(please specify: ______________)**

****PROGRAMMER NOTE: IF Q20=1 OR 3, CONTINUE, OTHERWISE SKIP TO Q22****

Q21. What type of fuel is used to power your water heating system?

1. Electricity
2. Natural (piped) gas
3. Propane
4. Something else **(please specify: ______________)**

Q22. Does your home have any of the following? (Please check all that apply)

1. Swimming pool
2. Spa/hot tub
3. None of the above [EXCLUSIVE]

Q26. Which of the following "Smart" appliances do you have in your home? By "smart" appliance we mean appliances that are connected to your smartphone, tablet or computer to give you information and control of the appliance. (*Please select all that apply*)

1. Refrigerator
2. Clothes washer
3. Clothes dryer
4. Dishwasher
5. Oven
6. Range / Cooktop
7. No Smart appliances [EXCLUSIVE]

Q27. How many plug-in electric vehicles do you garage at this property?

0. None
1. One
2. Two or more
3. Not sure

Q28. Are there any solar electric generation systems / panels (PV) operating at your property currently?

1. Yes
2. No

PROGRAMMER NOTE: IF Q28=1, CONTINUE, OTHERWISE SKIP TO TEXT BEFORE Q30.

Q29. What is the approximate installed capacity of all of the PV systems at your property?
[ENTER NUMBER] Kilowatts of capacity
998. Don't know / Not sure

Program Interest and Barriers

Now we would like to ask how interested you would be in different rate options that could make it possible for you to lower your overall electricity bill.

[PROGRAMMER: PLACE Q30 & Q31 ON SAME SCREEN]

Q30. First, consider an electricity rate in which the price for electricity more closely connects to the price of producing that electricity.

With such a rate, electricity consumed during "off-peak" hours in the early mornings, evenings, nights and weekends would be <u>cheaper than today</u>, while electricity consumed during "on-peak" hours in the late morning and afternoon weekday hours (when the most electricity is consumed) would be more expensive than it is today.

You could lower your monthly electric bill by as much as 5-10% by moving electricity use to off-peak hours or by reducing your use during on-peak hours.

If this electricity rate was available to you, how interested would you be in signing up for it?

Not At All Interested In Signing Up — Extremely Interested In Signing Up

1 2 3 4 5 6 7 8 9 10

Q31. Now, assume that this same electricity rate would be available, but with complete bill protection for the first two years. That is, you would be guaranteed to never pay more on the new rate than you would have paid on the standard, current rate, for the first two years.

If this electricity rate was available to you with bill protection in place for two years, how much more interested would you be in signing up for this rate?

Would Not Be Any More Interested In Signing Up — Would Be Much More Interested In Signing Up

1 2 3 4 5 6 7 8 9 10

[PROGRAMMER: PLACE Q32 & Q33 ON SAME SCREEN]

Q32. Now, consider an electricity rate in which electricity prices would vary for each hour of every day, depending on how much it cost to produce electricity during that hour.

While electricity prices could differ every hour under this rate, it would still be true that electricity prices would tend to be higher during times of "peak" demand, such as during weekday, summer afternoons, and lowest during times of "off-peak" demand (nights and weekends).

With this rate, you could potentially save as much as 5-10% by moving electricity use to times when electricity prices are lower, or reducing usage during times when electricity prices are highest.

If this rate option was available to you, how interested would you be in signing up for this program?

Not At All Interested In Signing Up — Extremely Interested In Signing Up

1 2 3 4 5 6 7 8 9 10

Q33. Now, assume that this same electricity rate would be available to you, but with complete bill protection for the first two years. That is, you would be guaranteed to never pay more on the new rate than would have been paid on the standard, current rate, for the first two years.

If such an electricity rate was available to you with bill protection in place for two years, how much more interested would you be in signing up for this rate?

Would Not Be Any More Interested In Signing Up — Would Be Much More Interested In Signing Up

1 2 3 4 5 6 7 8 9 10

Q34. You've been asked to consider two ways in which electricity rates could vary each day:

- One in which electricity prices would differ across a few time periods each day (like afternoons, evenings, etc.), with some periods having lower electricity rates, and other periods having higher electricity rates

- And, one in which electricity prices could vary across every hour, though it would still generally be true that electricity prices would be higher during hours of "peak" demand.

Assuming that both provided similar opportunities for you to save money, which type of electricity rate program would you most prefer?

1. A rate program in which electricity rates varied by a few time periods every day
2. A rate program in which electricity rates varied by each hour of every day
3. Prefer both equally

[PROGRAMMER: PLACE Q35 & Q36 ON SAME SCREEN]

Q35. Now consider another electricity rate in which electricity prices would be lower than they are today for all hours of the day and the year except for the hottest 10-12 days of the summer. For the hottest 10-12 days of the summer electricity prices would be much higher than they are today.

You could potentially lower your electric bill by as much as 5-10% by reducing or moving electricity use just during these 10-12 days each year.

If such an electricity rate was made available, how interested would you be in signing up for this rate?

Not At All Interested In Signing Up									Extremely Interested In Signing Up
1	2	3	4	5	6	7	8	9	10

Q36. Now, assume that this same electricity rate would be available, but with complete bill protection for the first two years. That is, you would never pay more on the new rate than would have been paid on the standard, current rate, for the first two years.

If this electricity rate was available to you with bill protection in place for two years, how much more interested would you be in signing up for this rate?

Would Not Be Any More Interested In Signing Up							Would Be Much More Interested In Signing Up		
1	2	3	4	5	6	7	8	9	10

Q37. You have been asked to consider several different types of electricity rates:

- In two of these options, electricity prices would vary by time every day (either every hour, or during larger time periods like afternoons, evenings, etc.), with some hours / periods having lower electricity rates, and other hours / periods having higher electricity rates
- In one of these options electricity prices would be higher only on the hottest ten days of the summer

Assuming that both of these rate options provided similar opportunities for you to save money, which type of electricity rate program would you most prefer?
1. A rate program in which electricity rates varied by hour or time periods <u>every day</u>
2. A rate program in which electricity rates varied <u>only on the hottest ten days of the summer</u>
3. Prefer both equally

Q38. The questions below outline concerns or opinions that people may have that might affect how they would react to the kinds of rate options we have been discussing.
Using a 10-point scale where '1' means you <u>strongly disagree</u>, and '10' means you <u>strongly agree</u>, please indicate how much you agree or disagree with each of the statements below.

[RANDOMIZE LIST ITEMS]	Strongly disagree									Strongly agree
	1	2	3	4	5	6	7	8	9	10
1. We just don't want to have to worry about how electricity costs might vary at different times of the day or year	○	○	○	○	○	○	○	○	○	○
2. We would be concerned that these rates would be a lot of trouble without much benefit	○	○	○	○	○	○	○	○	○	○
3. We just don't trust the utility to actually want to help us save us money.	○	○	○	○	○	○	○	○	○	○
4. We just want to be left alone to use electricity the way we want	○	○	○	○	○	○	○	○	○	○
5. We would be concerned that we just wouldn't be able to reduce our electricity usage during "peak" periods	○	○	○	○	○	○	○	○	○	○
6. We would be concerned that we just wouldn't know what to do differently during peak price periods in order to save money	○	○	○	○	○	○	○	○	○	○
7. It doesn't seem like it would be that hard to save money on these types of rates	○	○	○	○	○	○	○	○	○	○

Q39. Some utilities offer programs that are designed to help the utility meet customer demand for electricity during summer weekday afternoons when consumption of electricity is the highest. Participating customers help to increase the reliability of their electric service by allowing their usage to be managed during these times. Customers in these types of programs are often eligible to receive an incentive, depending on the number of times their usage is managed.

One way that other utilities manage customer demand is to install a device on air conditioners that allows them to cycle the compressor on and off for 30 minutes out of every hour. These periods usually happen on hot summer weekday afternoons, for no more than 10 days each summer. There may also be other appliances (pool pumps, dehumidifiers, etc.) which the customer might allow the utility to control.

Electric utilities in Michigan are considering programs like these and would like to know how interested their customers would be in participating. We recognize that there are many unknown details at this point, but if your electric utility did develop and offer a program like this and, for participating, you earned a $50 bill credit each year, how likely would you be to participate?

Not At All Likely To Participate — Extremely Likely to Participate

1 2 3 4 5 6 7 8 9 10

PROGRAMMER NOTE: IFQ39 = 7-10, CONTINUE; OTHERWISE SKIP TO Q41.

Q40. And if the same program was offered, but the bill credit was $25 per year, how likely would you be to participate in the program?

Not At All Likely To Participate — Extremely Likely to Participate

1 2 3 4 5 6 7 8 9 10

PROGRAMMER NOTE: IFQ39 = 1-6, CONTINUE; OTHERWISE SKIP TO Q42.

Q41. And if the same program was offered, but the bill credit was $100 per year, how likely would you be to participate in the program?

Not At All Likely To Participate — Extremely Likely to Participate

1 2 3 4 5 6 7 8 9 10

Q42. Another way that these energy management programs might work is that you could allow your utility to communicate directly with a Smart Thermostat in your home (either one you already have or one that would be installed by the utility). Under this sort of arrangement, the utility would send signals to your thermostat which would adjust the settings on your thermostat during peak usage times in the summer to a few degrees higher.

The advantage to this type of program is that it would mean not having to add a control device on your air conditioner, and you could agree with your electric utility ahead of time about how your thermostat settings would be adjusted during peak periods.

Under this sort of an arrangement, would you be more or less likely to participate in one of these programs compared to the program that involved installing a control device directly on your air conditioner, or other appliance?

Much Less Likely To Participate								Much More Likely to Participate	
1	2	3	4	5	6	7	8	9	10

Q43. The questions below outline concerns or opinions that people may have that might affect how they would react to the kinds of programs we have just discussed which would use Smart appliance interfaces to help your household use less electricity during peak periods.
Using a 10-point scale where '1' means you strongly disagree, and '10' means you strongly agree, please indicate how much you agree or disagree with each of the statements below.

[RANDOMIZE LIST ITEMS]	Strongly disagree									Strongly agree
	1	2	3	4	5	6	7	8	9	10
We just don't like the idea of the utility "talking" directly to our thermostat	○	○	○	○	○	○	○	○	○	○
This seems like it would be simple and easy to implement	○	○	○	○	○	○	○	○	○	○
We have to be able to control our thermostat how we want, when we want	○	○	○	○	○	○	○	○	○	○
There just wouldn't be enough benefit for us to do something like this	○	○	○	○	○	○	○	○	○	○

DEMOGRAPHICS

In order to help us classify your responses, the last few questions are on demographics.

Q44. Which of the following categories includes your household's total annual income before taxes in 2016? Please include the income of all people living in your home in this figure.

1. Less than $60,000
2. $60,000 or more

**PROGRAMMER NOTE: IF Q59=1, DISPLAY OPTIONS 1-7 AND 13; IF Q59=2, DISPLAY OPTIONS 8-13]

Q45. Which of the following categories includes your household's total annual income before taxes in 2016? Please include the income of all people living in your home in this figure.

1. Less than $10,000
2. $10,000 – $14,999
3. $15,000 – $19,999
4. $20,000 – $29,999
5. $30,000 – $39,999
6. $40,000 –$49,999
7. $50,000 – $59,999
8. $60,000 – $74,999
9. $75,000 – $99,999
10. $100,000 – $124,999
11. $125,000 – $149,999
12. $150,000 or more
13. Prefer not to say

Q46. Which of the following best describes your race or ethnic background?

1. White, Caucasian
2. Black, African American, Caribbean American
3. American Indian (Native American), Alaska Native
4. Asian
6. Hispanic, Latino
5. Native Hawaiian, Pacific Islander
990. Other [SPECIFY]
7. Prefer not to say

Those are all the questions we have for you today. Thanks for your participation!

DEFINITIONS

[THE DEFINITIONS IN THE TABLE BELOW WILL EACH BE SHOWN IN A POP-UP BOX THAT IS TRIGGERED BY A HYPERLINKED WORD OR PHRASE]

Word / Phrase	Definitions
Air-source heat pump	A single system that draws in outside air to use in both heating and cooling your home
Attic fan	A ventilation fan which regulates the heat level of a home's attic by exhausting hot air. Unlike a whole-house fan, which removes heat from the entire home, an attic fan *only* removes heat *from the attic area* of the home.

Central boiler with hot water/steam radiators or baseboards in individual rooms	A furnace that sends either hot water or steam to individual room radiators or baseboards to heat your home
Central warm air furnace with ducts/vents to individual rooms	A furnace that sends warm air to ducts or vents to heat your home
Conventional water heater with storage tank	A traditional water heater that heats a tank of hot water, and keeps that tank of water hot at all times. Most tanks range from 30-80 gallons in size.
Electric baseboard or electric coil radiant heating	Devices that use electricity directly to produce heat for your home from baseboards or under-floor heating.
Geothermal heat pump	A single system that uses water or fluid that circulates through underground piping to provide both heating and cooling for your home
Heat pump water heater	A system that uses a refrigeration cycle in reverse to draw heat out of the surrounding air to provide hot water in a traditional water heater storage tank
Smart Learning Thermostat	A smart learning thermostat is similar to a programmable thermostat, but it has Wi-Fi capability for programming and adjusting remotely and it also has either presence-sensing or geo-fencing capabilities. An example is the Nest Thermostat.
Tankless (instantaneous/on demand) water heater	A water heater that only heats water for delivery to your home when you ask for it by using hot water. These systems do not keep a tank of water hot at all times.
Wall furnace	A furnace that works "through the wall," meaning that it is a box that draws air directly from the outside and then warms it before sending the resulting warm air into a room.
Whole-house fan	A ventilation fan mounted in the ceiling of a central part of a home that removes heat from the *entire* home. It does this by first drawing that heat from the living areas of the home into the home's attic, and then pushing the heat trapped in the attic to the outside through vents. Unlike an attic fan, which only removes heat from a home's attic, a whole-house fan removes heat from the entire home.

Interview Guide

Introduction: {Introduce interviewer, discussion will focus on the small and medium business (SMB) market for demand response (DR) programs; responses are confidential in the sense that they will not be linked with your name or your business; the goal of the interviews is to help utilities to understand potential future market response to new DR programs in Michigan; ask for willingness to record the interview]

1. Background
    a. Respondent's title and responsibilities

    b. Type of DR programs managed/implemented in Michigan
    c. What percentage of their SMB customers use some type of automation to respond to events? What automation is used/ (Probe for PCTs, VSDs, etc.)
    d. Do any customers have an EMS? Do providers integrate with the EMS to enable response?
    e. Are there agricultural DR programs in Michigan? Is there potential for agricultural programs?
    f. If they have not implemented in Michigan, what types of DR programs have they implemented/managed in other areas of the Midwest?
2. General Market Questions
    a. To what extent do energy costs / issues get attention in the SMB market in Michigan? How / why / when do they get SMB customers' attention?
        i. What specifically are the energy-related issues that have been receiving the most attention from SMB customers? Why?
    b. What has been happening with electricity / gas prices? What do SMB customers expect to happen in the future? What does the respondent expect to happen in the future?
        i. Are there any other significant, energy-related market changes that have happened in the last few years?
            1. What changes have occurred?
            2. How have SMB customers responded to these changes?
            3. What has been the role of utilities?
    c. When customers focus on energy-related issues, has their focus been on EE or DR? Why? What are the implications of this focus? What sorts of things have they done?
3. Current Participation in DR programs

   Specifically, what types of DR programs are the most popular with SMB customers? Which are least popular?
    a. Why are these options popular (or not)? What are the benefits that appeal to customers?

i. Specifically what is it about DR programs that are attractive to SMB customers?
ii. What risk(s) are customers concerned about, and how are these mitigated?

b. Are dynamic pricing programs attractive to SMB customers? What type of dynamic pricing program is most attractive to SMB customers (probe for TOU vs. CPP or RTP)?
c. Would a Fast DR option get any traction with SMB customers? What percent of the market would be interested in Fast DR? What technology would be required for a successful program?
d. What is the role of their electric / gas utility in promoting DR programs? Does this help / hurt? What should utilities do differently?
e. What is the process for SMB customers making the decision to participate in new DR programs (who is involved over what time frame)?
    i. Does the decision-making process complicate things? How?
    ii. What can be done to make programs easier for customers to get through their internal processes?
    iii. What sources of information do SMB customers use in their decision to participate (including utility and peers)? What role did they (the respondent's firm) play?
    iv. What, ultimately, leads customers to make a final decision to proceed?
        1. Are there specific financial metrics that typically go into the decision? If so, what?
f. How does participation typically work out for these customers? Does it yield the benefits they sought?

4. Barriers to Participation
    a. Do SMB customers have a good understanding of the DR program offerings available to them?
        i. If no, what could be done to improve their understanding?

b. Do SMB customers know how to shift or reduce load?
    i. How difficult is it for them to put a response plan in place?
    ii. Can they shift or stop their hours of operation?
    iii. Are they receptive to automation?
    iv. What technologies are used to automate their response? (Probe for thermostat switches, EMS integration)
    v. What barriers do they face when trying to reduce load?
c. How easy is it for SMB customers to save money with DR?
d. What are some other reasons customers don't participate?
    i. How do customers balance risks and benefits? What risks outweigh those benefits?
    ii. Are the incentives sufficient? If not, what would be required?

Overcoming Barriers

1. What do you think would need to happen to make DR a viable option for small and medium businesses?
    a. What would be the attractive value proposition(s)?
    b. What role should automation play?
    c. Who would need to be involved in the communication and sales process (the utility? Who else?)
    d. What could a utility or DR provider do to help improve SMB customers' ability to respond?
    e. What risk(s) would be acceptable / not acceptable for SMB customers?
    f. Under what conditions would SMB customers consider participation?
        1. What sort of program?
        2. What incentive?
2. What other financial considerations would be relevant to SMB customers?
3. What will continue to be barriers? How can these be best ameliorated?

Closing

1. What is the future of the DR market for SMB customers? What new technologies/programs are going to impact the market in the next 10 years? The next 20 years?

Thank respondent

Utility DR Interviews

Introduction: {Introduce interviewer, discussion will focus on market for demand response (DR) programs; responses are confidential in the sense that they will not be linked with your name or your utility; the goal of the interviews is to help us understand potential future market response to new DR programs in Michigan; ask for willingness to record the interview]

Background

a. Respondent's title and responsibilities
b. What type of DR programs has your utility offered?
c. Have you offered program that focus on the Agricultural market? Do you think there is there potential in Michigan for agricultural programs?

Participation in DR programs

e. Specifically, what types of DR programs are the most popular with customers? Which are least popular?
   i. Why are these options popular (or not)? What are the benefits that appeal to customers?
   ii. What risk(s) are customers concerned about, and how are these mitigated?
f. Do you think dynamic pricing programs are attractive to customers? (probe for TOU vs. CPP or RTP)?
   i. Are residential customers responsive to price signals?
g. Would a Fast DR option get any traction in Michigan? Who would be interested in Fast DR? What technology would be required for a successful program?

Barriers to Participation

h. Do customers have a good understanding of the DR program offerings available to them?
i. Do customers know how to shift or reduce load?
j. Are customers receptive to automation?
k. How easy it is it for customers to save money with DR?
l. What are some other reasons customers might not want to participate?

Overcoming Barriers

1. What would be the attractive value proposition(s) to get customers interested in participating in DR?
2. What role should automation play?
3. Who would need to be involved in the communication and sales process (the utility? Who else?)
4. What will continue to be barriers? How can these be best ameliorated?

Closing

1. What is the future of the DR market in Michigan? What new technologies/programs are going to impact the market in the next 10 years? The next 20 years?

Thank respondent

C

APPENDIX C – DETAILED RESULTS AND INPUTS

We have included three files below which provide our detailed inputs and results. The input generator contains all the inputs for each program, by segment, and the two results files present the results for the technical achievable, and achievable cases respectively.

DR Input Generato - State of Michigan

DR_Model_State o Michigan_Standalc

DR_Model_State of Michigan_Integratec

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