ENVIRONMENTAL LAW & POLICY CENTER

Protecting the Midwest's Environment and Natural Heritage

January 12, 2018

Ms. Kavita Kale
Michigan Public Service Commission
7109 W. Saginaw Hwy.
P. O. Box 30221
Lansing, MI 48909

RE: MPSC Case No. U-18419

Dear Ms. Kale:

The following is attached for paperless electronic filing:

> Direct Testimony of Kevin Lucas, Michael B. Jacobs, R. Thomas Beach, and Philip Jordan on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, the Union of Concerned Scientists, and Vote Solar
>
> Exhibits ELP-1 – ELP-63
>
> Proof of Service

Sincerely,

Margrethe K. Kearney

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Margrethe Kearney
Environmental Law & Policy Center
mkearney@elpc.org

cc: Service List, Case No. U-18419

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

DIRECT TESTIMONY OF

KEVIN LUCAS

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

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I. INTRODUCTION AND QUALIFICATIONS.

Q. PLEASE STATE FOR THE RECORD YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Kevin Lucas. I am the Director of Rate Design at the Solar Energy Industries Association (SEIA). My business address is 600 14th St NW #400, Washington, DC 20005.

Q. PLEASE SUMMARIZE YOUR BUSINESS AND EDUCATIONAL BACKGROUND.

A. I began my employment at SEIA in April 2017 as the Director of Rate Design. SEIA is the national trade association for the U.S. solar industry. SEIA works with its 1,000 member organizations to advance solar power through education and advocacy. It seeks to champion the use of clean, affordable solar in America by expanding markets, removing market barriers, strengthening the industry and educating the public on the benefits of solar energy.

As Director of Rate Design, I work with other members of SEIA's State Affairs team to engage in various regulatory dockets. I have developed testimony in rate cases on rate design and cost allocation, worked on the New York Reforming the Energy Vision (NY-REV) proceeding on rate design and distributed generation compensation mechanisms, and performed a variety of analyses for internal and external stakeholders.

Before I joined SEIA, I was Vice President of Research for the Alliance to Save Energy (Alliance) from 2016 to 2017, a DC-based nonprofit focused on promoting technology-neutral, bipartisan policy solutions for energy efficiency in the built environment. In my role at the Alliance, I co-led the Alliance's Rate Design Initiative, a working group that consisted of a broad array of utility companies and energy efficiency products and service providers that was seeking mutually beneficial rate design solutions. Additionally, I performed general analysis and research related to state and federal policies that impacted energy efficiency (such as building codes and appliance standards) and domestic and international forecasts of energy productivity.

Prior to my work with the Alliance, I was Division Director of Policy, Planning, and Analysis at the Maryland Energy Administration, the state energy office of Maryland, where I worked between 2010 and 2015. In that role, I oversaw policy development and implementation in areas such as renewable energy, energy efficiency, and greenhouse gas reductions. I developed and presented before the Maryland General Assembly bill analyses and testimony on energy and environmental matters, and developed and presented testimony before the Maryland Public Service Commission on numerous regulatory matters.

I received a Master's degree in Business Administration from the Kenan-Flagler Business School at the University Of North Carolina, Chapel Hill, with a concentration in Sustainable Enterprise and Entrepreneurship in 2009. I also received a Bachelor of Science in Mechanical Engineering, cum laude, from Princeton University in 1998.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, Vote Solar, and the Union of Concerned Scientists.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. Yes, I am sponsoring Exhibits ELP-1 (KL-1) through ELP-56 (KL-56). These exhibits are all discover responses from DTE in this case.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION?

A. No, I have not.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE OTHER STATE UTILITY COMMISSIONS?

A. Yes. I have testified before the Maryland Public Service Commission in several rate cases[1] and merger proceedings.[2] Additionally, I have testified before the Maryland Public Service Commission in numerous rulemaking proceedings, technical conferences, and legislative-style panels, covering topics such as net metering, EmPOWER Maryland (Maryland's energy efficiency resource standard), and offshore wind regulation development.

I have also submitted testimony before the Public Utility Commission of Texas in a general rate case for El Paso Electric Company[3] and before the Public Service Commission of Nevada in a general rate case for Nevada Power Company.[4]

Q. PLEASE EXPLAIN YOUR EXPERIENCE THAT IS MOST RELEVANT TO THIS PROCEEDING.

A. For nearly two decades, I have performed quantitative analyses across a variety of sectors and industries. I worked as a consultant configuring software and developing technical specifications for custom programs and reports in the supply chain industry. In this capacity, I analyzed the operations of Fortune 500 companies to understand how they manufactured, stored, sold, and transported their products. These projects required an understanding of how complex systems are designed and managed, and how particular functions such as forecasting interacted with other functions such as inventory management.

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[1] Case 9311 (In re the Application of Potomac Elec. Power Co. for an Increase in its Retail Rates for the Distrib. of Elec. Energy) and Case 9326 (In re the Application of Balt. Gas & Elec. Co. for Adjustments to its Elec. & Gas Base Rates.)
[2] Case 9271 (In re the Merger of Exelon Corp. & Constellation Energy Grp., Inc.) and Case 9361 (In re the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.)
[3] Docket 46831, Application of El Paso Electric Company to Change Rates.
[4] Docket 17-06003, Application of Nevada Power Company d/b/a NV Energy for authority to adjust its annual revenue requirement for general rates charged to all classes of electric customers and for relief properly related thereto.

As I was transitioning from the consulting industry to the energy industry, I obtained my Masters in Business Administration. This education enabled me to expand my quantitative skills into new areas such as scenario planning, risk assessment, and making decisions under uncertainty. I also developed deeper skills in building and understanding financial models and proformas.

Once in the energy industry, I continued to apply my quantitative analysis skills to a variety of areas at the Maryland Energy Administration (MEA). I constructed models that assisted in the development of solar and offshore wind legislation, conducted policy and fiscal analyses on draft legislation, and frequently testified before the Maryland General Assembly to explain the impact of different bills. I worked with MEA's director to help inform the Governor's Office about various changes occurring in the PJM wholesale capacity markets and how they impacted the state's policies. I directed the effort of a diverse group of stakeholders (including state employees, utility employees, and energy efficiency and environmental advocates) and external consultants to create a new construct for Maryland's energy efficiency policy, including overseeing the development of an energy efficiency potential study very similar to the one performed by GDS Associates in this case.

I was the only state employee witness in the merger proceeding between Exelon Corporation and Pepco Holdings, Inc. My testimony ranged across many topics, including the development of new renewable generation, the potential impact of wholesale market changes on the finances of the combined company, and technical analysis on merger commitment related to renewable generation and energy efficiency.

I worked closely with the Maryland Department of Environment (MDE) on how to best attain the state's greenhouse gas reductions. This required detailed modeling of Maryland's policies such as its renewable portfolio standard and energy efficiency standard and the impact of potential retirements of coal plants and development of new natural gas plants. I also worked closely with the MDE and the Maryland Public Service

Commission staff on issues related to the Regional Greenhouse Gas Initiative, the collective of mid-Atlantic and northeast states seeking to reduce their aggregate greenhouse gas emissions.

In my time with SEIA, I have developed extensive testimony in rate case proceedings that analyzed topics such as cost allocation and rate design. In a rate case proceeding for El Paso Electric, I analyzed hourly generation and consumption data to challenge the utility's position that residential solar customers cost more to serve than residential non-solar customers. I used my understanding of utility distribution system planning and rate design to critique El Paso Electric's proposal to introduce a non-coincident peak demand charge for residential and small commercial solar customers.

Aside from rate cases, I serve as a general analyst for SEIA. I have performed internal analyses on the impact of netting periods for solar customers, reviewed RFIs and RFPs for utility procurements of solar, and constructed a model of the Maryland solar RPS market. I contribute to SEIA's efforts in the New York Reforming the Energy Vision (NY-REV) proceeding, with a focus on rate design and valuing distributed energy resources. Each of these projects requires me to pair my knowledge of the industry and energy markets with my financial and quantitative analysis skills.

The common thread through my career has been my strength in quantitative analysis, which has been supplemented in the past seven years with a deep understanding of the energy market. My experience is well-suited for this case. The purpose of this proceeding is to determine if DTE has sufficiently supported its claim that the Proposed Project is the most reasonable and prudent alternative out of many. To challenge this position, one must have a thorough understanding of the reams of data and analyses contained in the record, must account for and balance risk from imperfect information about the future, and must ultimately be able to synthesize all of this information to form fact-based recommendations. The consequences of this proceeding will impact DTE and its customers for decades to come, and based on my experience and analysis, DTE's Proposed Project is not the right solution.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony focuses on several aspects of DTE Electric Company's (DTE) certificate of necessity (CON) filing. First, I provide a background on the solar industry both nationally and in and around Michigan to provide some context on the scale (or lack thereof) of DTE's renewable energy ambitions. I also discuss the recent Michigan Public Service Commission Order on PURPA avoided costs, as well as the potential impact on the solar industry from the currently-pending International Trade Commission Section 201 petition.

Second, I discuss how DTE's concept of what the "goal" of the Integrated Resource Plan (IRP) is prevented it from considering alternative portfolios and instead structured the modeling to select a 1,100 MW natural gas fueled combined cycle electric generating facility (Proposed Project). I also critique DTE's flawed renewable energy and energy efficiency assumptions. I discuss the results of the 2017 update to the IRP and how, despite substantial changes in recent data, DTE did not revisit key aspects of its modeling. I also examine why DTE's proposed strategy makes it more difficult to reach its corporate goal to reduce carbon emissions by 80% by 2050.

Third, I evaluate DTE's two quantitative risk analyses that were performed by or for DTE. I conclude that the risk analyses are woefully deficient in numerous aspects, and that the conclusions that DTE draws from them cannot be supported by the underlying analyses.

Fourth, I discuss the scenario set forth by Vote Solar Witness R. Thomas Beach that highlights the critical flaws and insufficiencies in DTE's Proposed Project and demonstrates the availability of more prudent and reasonable alternatives to DTE's Proposed Project. I discuss Mr. Beach's choice of costs and deployment rates, supporting them with data found in Michigan and the surrounding regions.

Q. CAN YOU SUMMARIZE THE CONCLUSIONS YOU REACHED?

A. DTE failed to explore alternative solutions to meet its near-term power demand that could be less costly and less risky to its customers and that could better prepare the company for its ambitious long-term GHG emission reduction goals.

Fundamentally, DTE's initial framing of the "goal" of the IRP and what it means to be a "reliable" resource blinded it to examining alternative portfolios that were composed of a geographically distributed set of resources. DTE erroneously assumes that a resource must be dispatchable to be reliable. This results in the unjustified discounting of a portfolio of distributed assets comprised of solar, wind, energy efficiency, and demand response as "unreliable" and unable to meet DTE's resource adequacy needs. After casting aside this possibility in the earliest phase of its IRP, all of its subsequent actions were cascading errors that flowed from this decision. While I challenge myriad questionable choices and assumptions throughout the IRP, the initial framing of the question resulted in DTE structuring its modeling to artificially steer towards its preferred Proposed Project.

For instance, rather than immediately ramping up renewable energy deployments, even in its most aggressive High Renewable scenario, DTE added nearly 80% of incremental renewable generation starting in 2023, a year *after* the model needed to meet a capacity shortfall and after major federal tax credits had expired or been reduced. DTE also used a lower energy efficiency assumption despite its own modeling showing that a higher energy efficiency assumption would save customers $131 million, and failed to dramatically expand its demand response capability in the next five years despite studies showing major untapped potential.

Aggravating this core issue, the price forecasts used for renewable energy for the majority of its modeling runs were outdated, and even the more recent projections were well above other available forecasts. DTE also selected the least efficient system design for solar energy (south-facing, fixed-tilt), undercutting the ability of solar to help meet its capacity needs. Additionally, DTE's modeling appears to be only driven by capacity needs and will not choose less expensive renewable energy over more expensive gas generation if capacity needs are met. Each of these choices and assumptions increased the cost of scenarios with more renewable energy. However, the die was cast against a distributed portfolio well before these faulty assumptions regarding the ability of these resources to meet DTE's resource adequacy needs coursed through the model.

Putting aside this massive issue, DTE also failed to properly and sufficiently analyze the risk of the Proposed Project. One of DTE's two quantitative risk analyses used a methodology that produced essentially random results, making it unfit for comparing alternative portfolios. The other quantitative risk analysis at best represented about 1/10 of meaningful characteristics that DTE claimed were crucial to review. Additionally, DTE's Proposed Project exposes customers to sizable natural gas price risk as fuel costs dominate capital costs in the final accounting. Fixing critical errors in DTE's sole year-to-year analysis presented to show the overall benefits of the Proposed Plan to its customers demonstrates that the Proposed Plan is actually $1 billion more expensive than indicated. When key DTE errors are fixed, the net benefit to customers shifts to a net cost, and under DTE's own analysis, customers will pay $221 million before the plant produces a single kWh. Customers do not fully recoup this payment until at least 2030, and only after improperly including benefits from a second power plant that is outside the scope of this CON proceeding. (Exhibit A-10.)

Because of its improper framing of the question, DTE failed to consider other cost-effective alternative scenarios. It neglected to analyze what many consider a best-in-class alternative portfolio: aggressive and early builds of renewables, high levels of energy efficiency and demand response, and some allowance for PURPA projects. When this alternative was modeled by expert witness Mr. Beach, it is preferable to DTE's proposal both in terms of cost and risk. Not only that, but it is much more consistent with DTE's long-term corporate CO2 emission reduction goals.

DTE has not explored reasonable alternatives that could meet its customers' power needs at lower costs and with less risk. It has not demonstrated that the Proposed Plan is the most reasonable and prudent means of meeting its power need. Therefore, the Commission should reject the CON for its Proposed Project.

II. <u>BACKGROUND ON THE CURRENT AND FUTURE STATE OF THE SOLAR INDUSTRY</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A. I begin this section with an overview of the solar market, including a discussion of price and deployment history and forecasts from a national and regional perspective, to help provide context to DTE's renewable energy assumptions. I then discuss the current PURPA activity in Michigan and compare how PURPA markets developed in other states. Finally, I discuss the pending International Trade Commission trade case that affects solar cells and modules.

Solar Price and Deployment History and Forecasts

Q. PLEASE PROVIDE SOME BACKGROUND ON THE NATIONAL SOLAR MARKET.

A. The past decade has been one of incredible change and growth in the solar industry. The dominant trend has been a massive decrease in prices, with utility scale project costs falling from $6.20/watt in 2007 to $1.05/watt in H2 2017.[5] GTM Research, a leading analytical firm that performs detailed research on the solar market, breaks the cost declines into four main phases. The first phase, occurring prior to 2012, is characterized by major year-over-year reductions in module prices due to the increase in global manufacturing capability. The second phase, from 2012 to 2015, resulted from a reduction in balance of system (BOS) costs such as racking and wiring. The third phase, from 2015 to 2018, was driven by increased competition in the module and BOS markets, resulting in margin compression. Finally, in the fourth phase, from 2018 and beyond, additional price reductions will largely come from an effort to reduce soft costs such as

[5] *PV System Pricing H2 2017*, GTM Research

permitting and customer acquisition. Figure 1 below shows the price reduction at the end of each phase. By 2022, utility-scale project prices are projected to fall 87% – even after accounting for inflation – from just 15 years before.

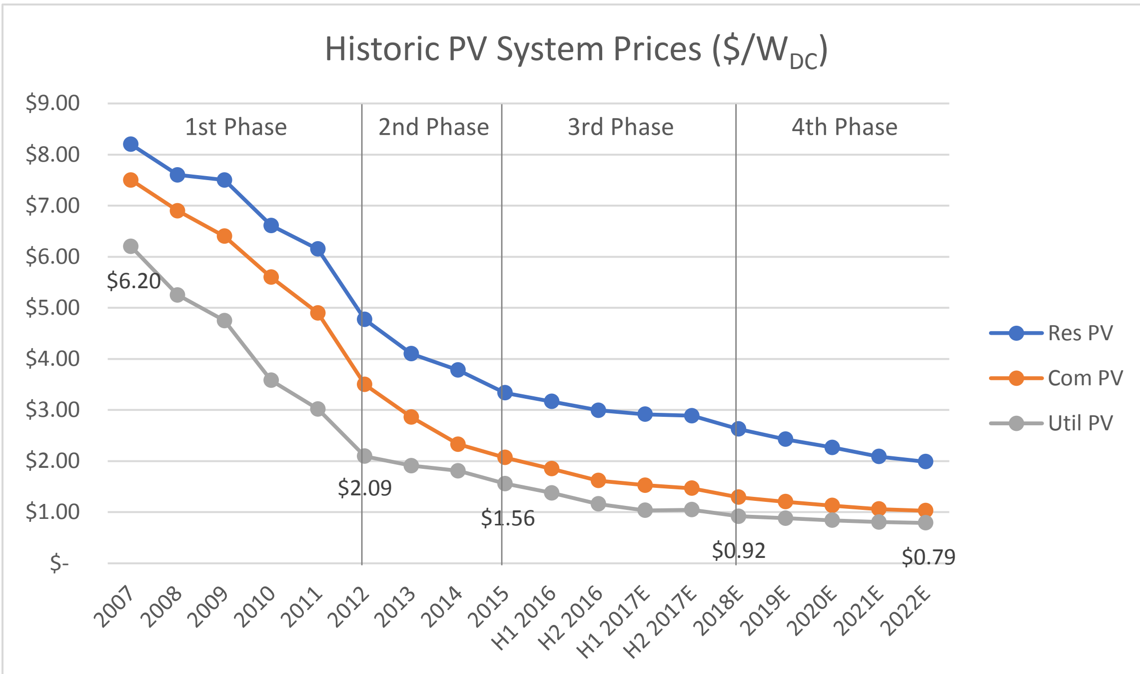

Figure 1 - Historic PV System Prices[6]

At the same time as system prices were falling, policies related to solar energy were implemented or strengthened at both the federal and state level. And in many instances, when a particular market reached a certain tipping point in terms of policy support, economics, or a combination of both, solar deployment started to grow at a much more rapid pace.

Initially, these policies, such as state renewable portfolio standards (RPS) and net metering, drove much of the deployment of solar. Much of this wave of deployment was behind-the-meter distributed generation (DG) that was able to take advantage of net metering statutes to reduce a homeowner's or business owner's electricity bill.

[6] All figures in my testimony were created by me and can be found in my workpapers unless otherwise noted.

State RPSs drove demand for renewable energy certificates (RECs). RECs are used as a compliance mechanism to demonstrate that the required entity has procured sufficient renewable energy represented by the REC. For each MWh of renewable energy that is required under the RPS, the responsible entity must generate or purchase and then retire one REC.

While Michigan has a 15% RPS that can be met with all qualifying resources (including solar), some states required RECs from just solar generation through a mechanism called a solar carve out. Frequently, the solar carve out would increase over time, creating an annually growing demand for solar RECs. By making the cost of failing to procure a solar REC high, the policy drove the demand for new solar facilities. Industry responded in kind, dramatically increasing the number of people employed by solar companies and inventing market innovations such as the residential power purchase agreement (PPA). Today, nearly 260,000 people are employed by the solar industry in the U.S.[7]

More recently, the Public Utilities Regulatory Policies Act (PURPA) has had a large impact on solar deployment. Under PURPA, a utility is required to purchase the output of a qualifying facility (QF) at its avoided cost. The avoided cost is specific to a particular utility, as is the scope and duration of the offtake agreement. As solar costs fell, utility-scale projects were able to be financed and developed at avoided cost rates. This led to a significant increase in installations in states such as North Carolina, Nevada, and Utah. The Michigan Public Service Commission recently issued an order establishing the avoided costs for Consumers Energy. I will discuss the potential impact of this order below, but it is possible that Michigan might see a similar ramp up in PURPA projects as was seen in other states.

[7] https://www.seia.org/solar-industry-data

Alongside these changes, direct corporate purchasing of renewable energy has also reached a tipping point. Several years ago, a few early adopters began purchasing renewable energy as part of their corporate sustainability goals. Now, the movement has gained substantial traction, with 118 companies such as Michigan-based General Motors,[8] Google,[9] Amazon,[10] and Walmart[11] announcing plans to run on 100% renewable energy.[12] Collectively, these companies consumed 107.4 TWh,[13] or roughly the amount of electricity that was consumed in the entire state of Michigan.

Each of these tipping points has been reached in part because costs fell sufficiently to reach the next set of customer demand at a price the customers were willing to pay. Rooftop PV worked in the early 2010s because of retail net metering and value from solar RECs. PURPA projects took off a few years ago when system costs fell below the avoided cost threshold. But now, solar is arriving at another tipping point: it is becoming economic when compared to traditional, fossil fuel-powered resources.

The timing of this tipping point depends on both the cost of the PV system as well as the solar resource of the state where it is installed, but PPA prices for solar are falling to new lows and are now in the range of conventional energy sources. One recent example is from NV Energy, which is seeking approval for two 25-year PPAs priced at $34.20/MWh with no escalator (meaning prices actually decline in real dollars over time). This figure is very close to NV Energy's energy cost of $32.43/MWh, and has the added benefit of locking in this price with no escalator and no price risk for 25 years.[14]

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[8] http://media.gm.com/media/us/en/gm/home.detail.html/content/Pages/news/us/en/2016/sep/0914-renewable-energy.html
[9] https://environment.google/projects/announcement-100/
[10] https://aws.amazon.com/about-aws/sustainability/
[11] https://news.walmart.com/2016/11/04/walmart-offers-new-vision-for-the-companys-role-in-society
[12] http://re100.org/http:/there100.org/
[13] http://media.virbcdn.com/files/a9/55845b630b54f906-RE100AnnualReport2017.pdf
[14] https://www.utilitydive.com/news/nv-energy-boasts-lowest-cost-ppas-for-2-proposed-solar-projects/510340/

The solar industry continues to drive down prices, increase panel efficiency, and reduce annual degradation. As solar PV panels become cheaper, produce more energy, and lose less production each year, the levelized cost of energy (LCOE)[15] will only fall further. By contrast, natural gas price forecasts are projected to increase over time, making energy from these resources more expensive. While it is unclear exactly when this economic tipping point will arrive in each state, it is clear that we continue to march toward it.

Q. PLEASE DESCRIBE SOME EXPECTED TRENDS IN THE NATIONAL SOLAR MARKET.

A. I expect the decrease in solar LCOE to continue for the foreseeable future. While the solar industry could previously count on falling panel prices to continue to drive massive year-over-year reductions in the LCOE of a system, as panel prices now make up a smaller and smaller portion of the system, opportunities to reduce costs further have shifted to other areas. Although these declines are projected to continue, the panels today make up less and less of the total cost of system. This drove innovation in non-module cost reduction. Industry developed new racking systems, better inverter designs, and less expensive ways of acquiring customers.

This innovation has driven down the price of solar projects significantly since 2010. When the U.S. Department of Energy launched its SunShot initiative in 2011, it had a goal to reduce the LCOE of utility-scale systems to $0.06/kWh by 2020. This was particularly bullish, given that costs at that time were $0.28/kWh. Earlier this year, DOE announced that it had met its 2020 utility-scale goals – three years early. Rather than pat itself on its back, DOE doubled down with a new goal to reduce costs in half again by

[15] The LCOE is denominated in $/kWh and is a measure of the total cost of the PV system spread over the lifetime production of the system. The formulas enable different technologies such as PV, wind, and natural gas combined cycle plants with different generation profiles and costs to be compared to each other on an apples-to-apples basis.

2030 to $0.03/kWh.[16] In support of this goal, DOE, industry, national labs, and academia continue to support basic research to reduce manufacturing costs, increase panel efficiency, better predict panel degradation, and investigate novel materials that could lead to panel breakthroughs.[17]

Q. PLEASE PROVIDE SOME BACKGROUND ON THE REGIONAL SOLAR MARKET IN MICHIGAN AND SURROUNDING STATES.

A. Until the completion of several large projects in 2017, Michigan had lagged behind most other Midwest states in terms of solar deployment. In 2010, there was very little deployment in any Midwest state. Ohio and Illinois led the pack with about 20 MW and 10 MW, respectively.[18] By the end of 2016, states such as Indiana, Minnesota, and Missouri made clear gains in the quantity of solar deployed, while Michigan fell behind all states except Wisconsin. Figure 2 below shows how the trajectory of these states evolved since 2010.

[16] https://energy.gov/eere/solar/articles/2020-utility-scale-solar-goal-achieved
[17] https://energy.gov/sites/prod/files/2016/02/f29/PV%20Fact%20Sheet-508web.pdf
[18] Data is taken from GTM Research U.S. Solar Market Insight Q3 2017.

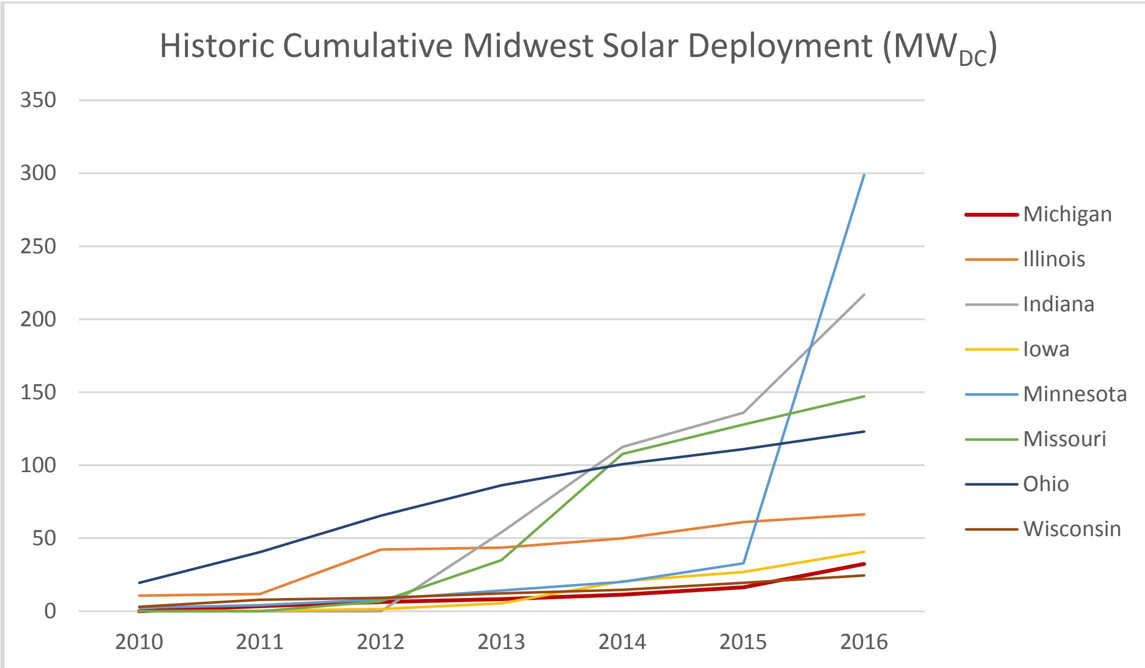

Figure 2 - Historic Midwest Solar Deployment

Looking at more recent history and forecasted installations, a similar trend emerges. Illinois recently passed legislation that will ultimately require at least 4,300 MW of wind and solar by 2030, with some of the initial projected builds captured in Figure 3 below.[19] Minnesota continues its strong growth in community solar installations. Indiana saw a sizable jump in its market in 2016 and 2017. While Michigan does improve upon its position compared to the previous chart, it is projected to remain well behind many surrounding states in the coming years. There is, however, one important factor missing from the chart below: it was made before Michigan's PURPA decision for Consumers Energy.

[19] https://citizensutilityboard.org/future-energy-jobs-act/

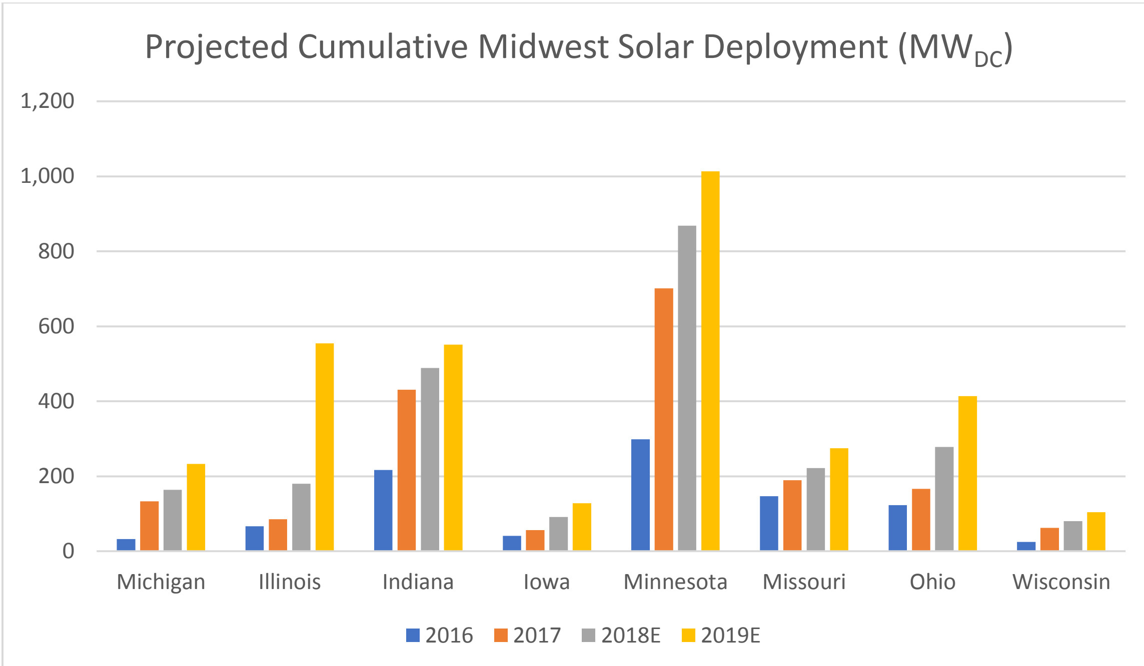

Figure 3 - Projected Cumulative Midwest Solar Deployment

Michigan PURPA Activities

Q. HOW MIGHT THE RECENT PURPA RULING AFFECT THE MICHIGAN SOLAR MARKET?

A. The PURPA ruling has the potential to be transformative. As is discussed later in my testimony, several states have seen dramatic increases in solar projects supported by PURPA. While the Commission has not finalized DTE's avoided costs, it has finalized Consumers Energy's avoided costs. As discussed in its November 21, 2017 Order,[20] the Commission finalized the calculation methodology for avoided costs for qualifying facilities (QF) based on a combination of costs from a natural gas combined cycle plant and a natural gas combustion turbine plant. It also mandated Consumers use a standard PPA contract for projects up to 2 MW_{AC} for up to 20 years, although the 2 MW_{AC} limit will be revisited during Consumers' next PURPA review.

[20] http://www.michigan.gov/documents/mpsc/U-18090_11_21_2017_606668_7.pdf

Q. WHAT WERE THE RESULTS OF THE AVOIDED COST CALCULATION FOR CONSUMERS ENERGY?

A. The methodology approved by the Commission calculated the value of avoided capacity at $140,505/ZRC-year. This value is to be paid to a QF in any year when Consumers Energy's 10-year planning horizon projects a need for new capacity. In years when Consumers Energy does not project a need for new capacity, the avoided capacity cost reverts to the MISO planning reserve auction clearing price (ACP).[21] This price has varied substantially in past years, from $26,280/MW-year to $547.50/MW-year.[22]

The avoided cost calculation offers three different options to solar and wind QFs.[23] The first is based on the actual MISO Day Ahead locational marginal price (LMP), adjusted for line losses and a fixed investment cost attributable to energy (ICE).[24] The second option is based on an LMP forecast, also adjusted for line losses and ICE. The third option is based on the expected cost of energy from a proxy natural gas combined cycle plant. Figure 4 below shows values for options 2 and 3.

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[21] A zonal resource credit (ZRC) is the quantity of capacity that a QF receives under MISO's planning reserve auction process. DTE used default values of 0.5 ZRC / MW_{AC} for solar and 0.156 ZRC / MW for wind for this case.

[22] https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017-2018%20Planning%20Resource%20Adequacy%20Results.pdf

[23] A fourth option only available to Run-of-River hydro QFs is not discussed here.

[24] ICE represents the additional capacity cost of combined cycle plant that was used as the proxy for energy costs above the cost of capacity from a combustion turbine plant that was used as the proxy for capacity costs.

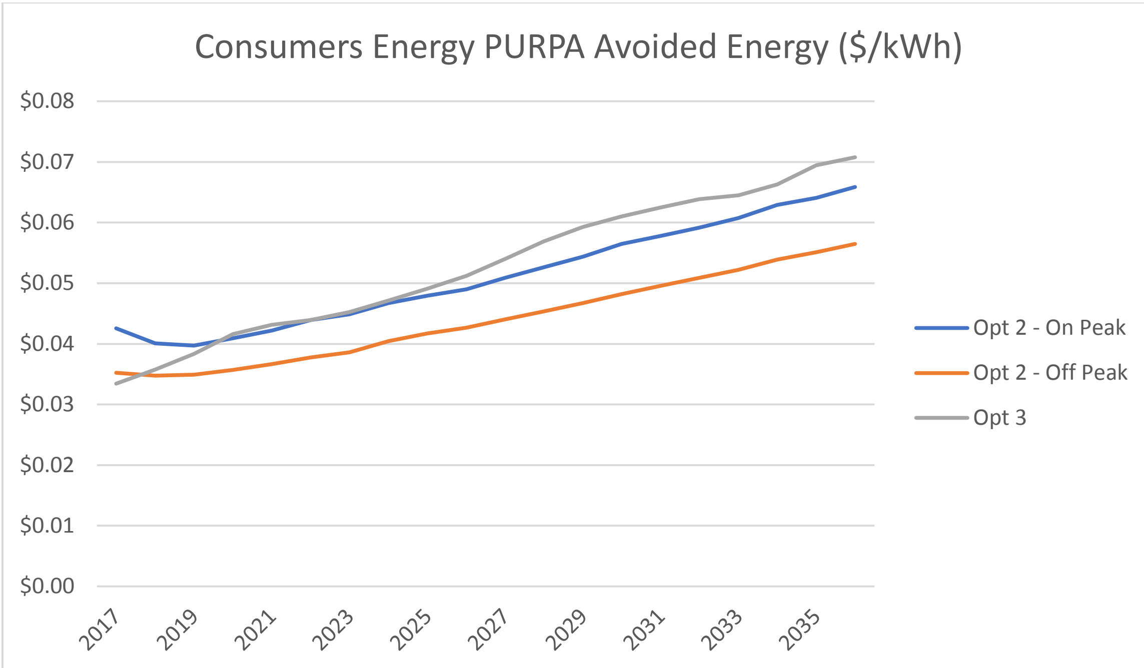

Figure 4 - Consumers Energy PURPA Avoided Costs

Q. HAS THE COMMISSION PUBLISHED THE FINAL AVOIDED COST VALUES FOR DTE?

A. No. However, the language in the July 31, 2017 Commission Order[25] for DTE substantially tracks that of the Consumers Energy Order. This is a strong indicator that the DTE results will be substantially similar to Consumers Energy.

Q. WHAT IS THE REVENUE THAT A SOLAR PROJECT MIGHT EXPECT UNDER THESE AVOIDED COSTS?

A. Given the wide range in potential capacity prices, the value of the PURPA project will depend strongly on whether or not there is a need for new capacity within the 10-year planning horizon. Using the example values from Consumer Energy Option 3, I modeled a hypothetical 2 MW_{AC} fixed-tilt and single-axis PV system[26] using the same discount

[25] http://efile.mpsc.state.mi.us/efile/docs/18091/0093.pdf
[26] More details about the operational characteristics of trackers is found in Section III of my testimony below.

rate as DTE's Market Valuation spreadsheets,[27] although it is possible that a private developer will have a different cost of capital than DTE.

The results are shown in Figure 5 below. The NPV of the energy payments is \$659/kW$_{DC}$ for fixed-tilt systems and \$705/kW$_{DC}$ for single-axis tracking systems. The NPV of the capacity payments varies substantially depending on whether or not there is a forecasted capacity need within the 10-year planning horizon. When there is, the avoided capacity values are comparable to the energy values. When there is not, the avoided capacity values are much lower.

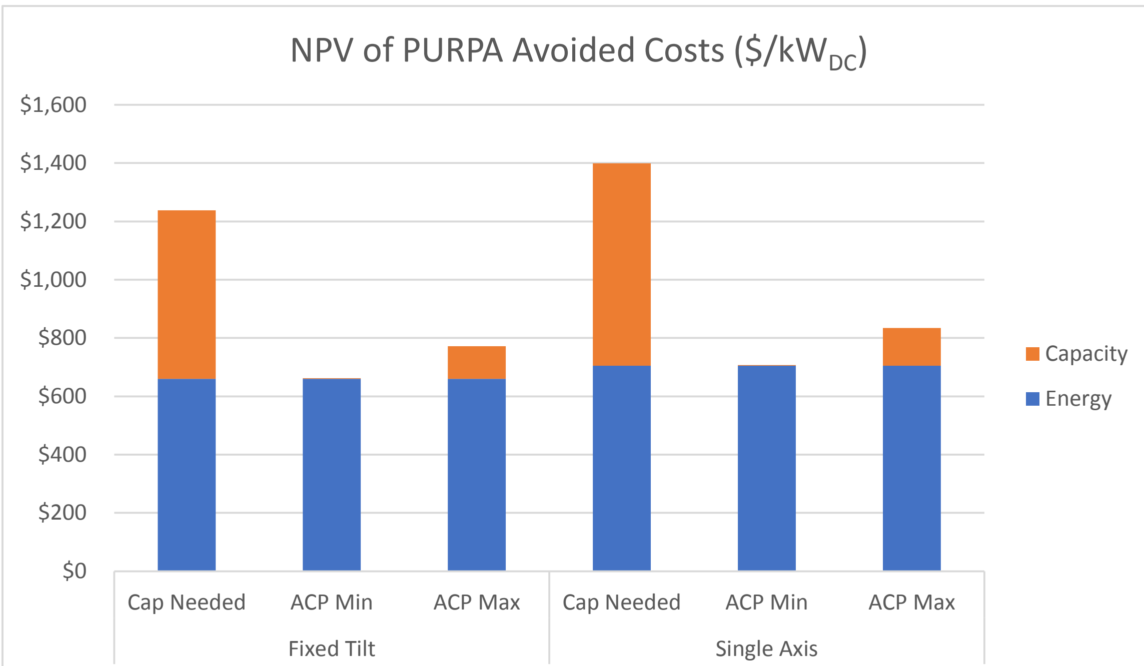

Figure 5 - NPV of PURPA Avoided Costs

Q. HOW TO YOU INTERPRET THESE RESULTS?

A. On a basic level, if the NPV of the PURPA revenues is equal or exceeds the NPV of the construction and ongoing costs such as O&M of the project, then investing in the project will be a good financial decision for a developer. Given that Mr. Beach uses 2018 cost

[27] 7.43% as found in WP KJC-4 through KJC-24.

estimates between \$909 and \$984 per kW_{DC} for fixed-tilt systems and between \$1,031 and \$1,106/ per kW_{DC} for single-axis tracking systems,[28] it is highly likely that developers will want to invest in PURPA projects in Michigan when there is a capacity need within the 10-year planning horizon. For years where there is not a capacity need, the PURPA revenues may not be enough to incent development at current system price levels.

Q. IS THERE CURRENTLY A CAPACITY NEED FOR DTE WITHIN A 10-YEAR PLANNING HORIZON?

A. Yes. The justification for DTE's CON in this proceeding is that it projects a capacity shortfall in 2022 after the retirement of several coal plants. Even after the Proposed Project is completed, DTE assumes that up to 300 MW of purchases will be used to balance short-term capacity imbalances. Within the 10-year planning horizon applicable to PURPA, its 2016 Reference case projects capacity shortfalls each year between 2023 and 2028, even after the addition of the Proposed Project. (WP KJC-2.) Its 2017 Reference case update keeps these years and adds 2018 to this list years with projected shortfalls. (WP KJC-323.) Therefore, when the Commission finalizes DTE's PURPA avoided costs rates, one should expect that the higher capacity value will be used for projects in the coming years.

Q. DOES DTE ACKNOWLEDGE THAT IT HAS A CAPACITY NEED WITHIN THE 10-YEAR WINDOW?

A. Bizarrely, no. As recently as December 21, 2017, DTE sent a communication to renewable generators entitled "PUPRA Qualifying Facility Notification" that concluded with the sentence "The Company presently forecasts that it has no additional capacity needs in the next 10 years." (ELPCDE-11.19, Ex. ELP-1 (KL-1))

[28] See Beach Workpapers. Low range represents no action from International Trade Case, while high range represents outcomes consistent with the commissioner's recommendations.

Q. HOW CAN YOU RECONCILE THESE CONFLICTING STATEMENTS?

A. I cannot. DTE's entire CON request is predicated upon identifying a power need and then demonstrating that its Proposed Plan is the most reasonable and prudent means to meet it. If DTE does not acknowledge that there is an additional capacity need in the next 10 years, it is unclear why it is requesting hundreds of millions of dollars to build the Proposed Project.

Q. DESPITE THE OBVIOUS NEED FOR CAPACITY WITHIN THE NEXT 10 YEARS, DID DTE EXPLICITELY INCLUDE ANY NEW PURPA PROJECTS IN ITS IRP?

A. No. It not only assumes no new PURPA projects, but also that existing PURPA contracts will not be renewed. In its 2016 Reference scenario, DTE lists 788 MW of "PU-PA2" projects in 2016, which represents PA 2 and PURPA contracts. (WP KJC-1, STDE-7.1.) By 2040, this figure drops to 1 MW. While DTE has assumed that it will build or procure additional wind and solar resources, and that PURPA projects could make up part of its annual market purchases, it has made no explicit allowance for additional capacity that the pending PURPA order might produce that may be in excess of its own renewable build projections. (ELPCDE-9.2b, Ex. ELP-2 (KL-2))

International Trade Commission Section 201 Proceeding

Q. PLEASE DISCUSS THE PENDING INTERNATIONAL TRADE COMMISSION PROCEEDING RELATED TO SOLAR CELLS AND MODULES.

A. In May 2017, Suniva, later joined by SolarWorld, filed a petition to the International Trade Commission (IntTC) under Section 201 of the 1974 Trade Act.[29] This section of the statute allows for temporary relief for domestic industry when imports are causing

[29] More information on the Section 201 case can be found at https://www.seia.org/initiatives/solar-section-201-case-frequently-asked-questions

"serious injury." SEIA is adamantly opposed to the petition, and strongly believes that the case is without merit. The negative impacts from the tariffs would do much more harm than good to the overall solar industry, and any funds recovered through tariffs would be directed to the general funds of the U.S. Treasury, not domestic solar manufacturers.

In its petition, Suniva claims that competition from modules (the industry name for a solar panel) and solar cells (the components that make up modules) from other countries are forcing US manufacturers to close as they are unable to compete against the less expensive imports. In the odd structure of a safeguard case, Suniva does not need to show any illegal action (such as dumping or unlawful government support) by a competing company or nation. Rather, Suniva merely needs to show that it has been injured, and that no factor is greater than imports in causing such injury. Suniva initially asked for a protective tariff of $0.40/watt for each imported cell, and a minimum price of $0.78/watt per module. These very high proposed tariffs would fall slightly over four years, at which point they would be removed. Given that module prices were roughly $0.38/watt at the end of 2016, the proposal would have more than doubled the price of solar modules.

This case is different from the 2012 anti-dumping trade case. In that proceeding, the IntTC investigated whether China was illegally "dumping," or selling panels below their actual price, on the U.S. market. The IntTC found that China was dumping their products into the U.S. and imposed tariffs against Chinese solar imports. In a Section 201 case, however, the petitioners do not have to demonstrate that imports are illegally being sold at artificially low levels, just that they are doing "serious harm" to domestic manufacturers. Any relief that would be imposed would affect all countries that import solar cells and modules to the US, unless specifically exempted by the IntTC.

The Section 201 case has several phases. First, the IntTC must determine whether or not there is "injury"; that is, are the imports actually causing harm to the domestic industry that brought the petition. The second phase is the "remedy" phase, where potential remedies are discussed and the IntTC delivers its recommendations to the president. The final "relief" phase is the decision phase, when the president must decide on what, if any, action to take. The president can accept the recommendations of the IntTC, impose different remedies, or do nothing.

After the president makes a determination, another nation may make an appeal to the World Trade Organization (WTO). If the WTO finds that the relief granted by the president violates international trade laws, it cannot force the United States to rescind the tariff, but it can allow other countries to implement retaliatory tariffs of their own that, in the past, have been significant enough to curtail safeguard actions before their four-year initial statutory limit has passed. Importantly, these tariffs do not have to be limited to solar products, but can be leveled on any exports from the U.S.

Q. WHAT IS THE CURRENT STATUS OF THE INTTC CASE?

A. The IntTC determined that there was injury on September 22, 2017. After that determination, a public hearing was held on October 10, 2017, to discuss potential remedies. On November 13, 2017, the IntTC sent its recommendations to the president. The IntTC did not agree on one remedy; therefore, there is no formal IntTC recommendation, but rather a series of individual reports from IntTC commissioners. On November 27, 2017, a U.S. Trade Representative asked the IntTC for additional information on "any unforeseen developments that led to the articles at issue being imported into the United States in such increased quantities as to be a substantial cause of serious injury."[30] This action extended the due date for the final decision, which is now due on or before January 26, 2018.

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[30] https://d12v9rtnomnebu.cloudfront.net/paychek/1243576-629905.pdf

Q. WHAT ARE THE POTENTIAL OUTCOMES OF THE INTTC CASE?

A. Due to the wide latitude the president has in this matter, the potential outcomes are varied. As mentioned above, the president can accept one of the IntTC commissioner recommendations, decide upon his own remedy, or do nothing. That said, the IntTC recommendations are currently public and can be analyzed for their potential impact.[31]

Of the four commissioners, three recommended various schedules of tariffs and quotas on imported cells, as well as an *ad valorem* tariff on modules. One commissioner suggested a different approach that would set a quota for imported products that would be administered through an auction for import licenses. The revenue raised by the licenses would be used to assist domestic solar cell and module product manufacturers. The levels of the quota and tariff recommendations are summarized below in Figure 6. It is worth noting that none of the recommendations were anywhere near the levels of relief sought by the petitioners.

[31] https://d12v9rtnomnebu.cloudfront.net/paychek/ITC_Final_recs.pdf

U.S. ITC Recommended Remedies By Commissioner

Commissioner Broadbent	Year 1	Year 2	Year 3	Year 4
Quota (cells and modules)	8.9 GW	10.3 GW	11.7 GW	13.1 GW
Mexico Quota (included in overall quota)	0.72 GW	0.84 GW	0.95 GW	1.07 GW
Estimated Import License Auction Proceeds	$89 Million	$14 Million	$14 Million	$14 Million
Commissioner Schmidtlein	**Year 1**	**Year 2**	**Year 3**	**Year 4**
Cell Quota Volume	0.5 GW	0.6 GW	0.7 GW	0.8 GW
Cell Tariffs Below Quota	10.00%	9.50%	9.00%	8.50%
Cells Tariffs Above Quota	30%	29%	28%	27%
Module Tariffs	35%	34%	33%	32%
Commissioners Williamson and Johanson	**Year 1**	**Year 2**	**Year 3**	**Year 4**
Cell Quota Volume	1 GW	1.2 GW	1.4 GW	1.6 GW
Cell Tariffs Below Quota	0%	0%	0%	0%
Cells Tariffs Above Quota	30%	25%	20%	15%
Module Tariffs	30%	25%	20%	15%

Source: GTM Research

Figure 6 - IntTC Recommendations

Q. HOW MIGHT THE INTTC DECISION AFFECT THE SOLAR MARKET?

A. As the specific remedies have not been determined, it is currently impossible to predict how the market will respond to relief, if any is granted. It is almost certain that an appeal will be made to the WTO by an aggrieved nation, although the tariffs will remain in effect during the appeal. The last time there was a Section 201 trade case, involving steel in 2001, the case was appealed and the U.S. lost (in fact, the U.S. has lost every Section 201 case that has been appealed to the WTO). European Union countries created a suite of duties of their own, some targeted at industries in key swing states. The Bush administration rescinded the tariffs in 2003 just before the tariffs were set to take effect.[32]

[32] https://www.bloomberg.com/news/articles/2017-11-15/cheese-and-bourbon-face-risk-of-backlash-from-u-s-solar-tariff

GTM Research has performed some analysis on the potential relief recommended by the IntTC commissioners.[33] Generally speaking, these tariffs would increase module prices between $0.10/watt and $0.11/watt in 2018, with the incremental cost falling to $0.04/watt and $0.09/watt in 2021, the final year of the tariff.

Any increase in price will harm the industry. Given that modules make up a larger fraction of the cost for utility-scale systems than for commercial or residential systems, this sector stands to be the most impacted. However, market analysts such as GTM Research project that system prices will continue their fall notwithstanding the tariffs, reducing the impact of the tariffs on an absolute if not relative basis.

Q. GIVEN THE UNCERTAINTY AROUND THE INTTC OUTCOME, DO YOU STILL RECOMMEND THAT DTE PURSUE AGGRESSIVE SOLAR DEVELOPMENT IN THEIR IRP?

A. Absolutely. Although any tariff or other form of trade relief would cause disruption to the U.S. solar industry, there is little doubt that, absent a severe remedy along the lines proposed by petitioners, the solar industry will survive, although potentially in fewer geographic markets and with project cancellations commensurate with the level of trade relief imposed. While analysts have shown that market prices have ticked up modestly in the past 6 months over uncertainty in this trade case and other factors, the long-term downward trend in PV prices will continue according to analysts. If tariffs are imposed, they will almost certainly be challenged at the WTO, and precedent suggests the U.S. will lose. If they do remain in effect, the recommendations of the IntTC make noticeable but less severe impacts than what was originally requested.

Additionally, it is imperative that DTE act quickly to take advantage of the federal investment tax credit (ITC). The ITC remains at its current 30% level through 2019

[33] *U.S. PV System Pricing H2 2017: Forecasts & Breakdowns*, GTM Research, December 2017.

before stepping down over the following years. By building or purchasing solar projects earlier, rather than waiting past the expiration of the tariffs, DTE will be able to capture more benefits from solar for its customers.

III. DTE'S INTEGRATED RESOURCE PLAN AND PROPOSED PROJECT ARE BASED ON FAULTY ASSUMPTIONS

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A. I begin this section with the fatal flaw of the IRP – DTE's decision to define the requirements of the Proposed Project in a manner that incorrectly leads it to dismiss consideration of a distributed portfolio of assets to meet its power needs. I then provide a high-level overview of DTE's IRP and its Proposed Plan, followed by an examination of the issues I have with DTE's renewable energy and energy efficiency assumptions. In short, DTE's solar cost projections are too high, its deployment forecast too low, and its choice of only considering fixed-tilt, south-facing systems understates solar's energy and capacity potential. Additionally, its energy efficiency and demand response assumptions consistently underestimate the ability of these resources to help meet DTE's load. From there, I investigate the 2017 IRP Update that DTE performed, with a focus on its consistency with DTE's stated CO2 reduction goals. Finally, I critique DTE's presentation of the financial impacts of the Proposed Plan as misleading.

Q. WHAT IS YOUR OVERARCHING CONCLUSION ABOUT DTE'S 2017 IRP AND PROPOSED PROJECT?

A. In this proceeding, DTE is seeking a Certificate of Need (CON) that affirms that "the size, fuel type, and other design characteristics of the Proposed Project represents the most reasonable and prudent means of meeting that power need (Section 6s(3)(b))" (Dimitry Direct at 11.) Through a series of choices about how to frame the power need, what assumptions to use, how to weigh different factors against each other, and how to interpret the results, DTE failed to explore alternative solutions that could be less costly and less risky to its customers and that could better prepare the company for its ambitious long-term GHG emission reduction goals. Ultimately, I believe that the Proposed Plan is not the most reasonable and prudent means of meeting its power need, and therefore DTE has failed to meet its burden of proof needed to obtain a CON.

Q. HOW DID YOU ARRIVE AT THIS CONCLUSION?

A. I arrived at this conclusion after a thorough review of DTE witnesses' direct testimony, exhibits, workpapers, and data request responses.

I began my analysis by reviewing DTE direct testimony and the 2017 IRP plan found in Witness Chreston's Exhibit A-4 2nd Revised (IRP Report). Overall, I found the IRP Report to be reasonably approachable for an informed reader and appreciated the structure of the document and step-wise manner in which the authors went through the process from the load forecast development to generation options overview to the construction of the model to the risk analysis of the results.

If one only read the report, one might assume the conclusions that DTE made in the IRP were reasonable and supported by more detailed analysis. However, as I reviewed the analysis and workpapers that supported the IRP, and asked discovery questions about their development, I not only became convinced that DTE's Proposed Plan was not the best answer to the questions it posed, but also that the questions it posed were themselves flawed.

As revealed through discovery, and discussed in detail throughout my testimony, DTE made assumptions and choices that artificially "steered" its models towards its preferred Proposed Project, a new natural gas combined cycle (NGCC) power plant to be fully online by 2023. These assumptions and choices led the models down a path to a NGCC, not because it was the best option from all viable alternatives, but rather because it conformed to the inappropriate constraints that DTE set for its analysis. Further, even if one accepts the constraints, DTE still has not demonstrated that the Proposed Project is the least risky choice for its customers.

DTE's Fatally Flawed Definition of Reliability Leads it to Dismiss Out of Hand a Portfolio of Distributed Assets

Q. HOW WOULD YOU CHARACTERIZE DTE'S OVERARCHING PURPOSE AS A UTILITY SERVING MICHIGAN CUSTOMERS.

A. As a regulated utility, DTE has an obligation to serve the expected load of its customers in a safe and reliable manner. It seeks to do this while also keeping customers' costs reasonable and affordable, and has made public goals to reduce the environmental footprint of its generation fleet.

Q. WHAT IS DTE REQUESTING IN THIS PROCEEDING?

A. It is requesting three CONs in this proceeding. The first is that the power to be supplied as a result of the Proposed Project is needed. The second is that the size, fuel type, and other design characteristics of the Proposed Project represents the most reasonable and prudent means of meeting that power need. The third is that the estimated capital costs and the financing plan for the Proposed Project, including, but not limited to, the costs of siting and licensing the Proposed Project and the estimated cost of power from the Proposed Project, will be recoverable in rates from the Company's electric utility customers. (Dimitry Direct at 10-11.)

Q. DO YOU AGREE WITH DTE THAT THERE IS A NEED FOR POWER IN THE NEAR FUTURE?

A. Yes. DTE plans to retire several coal plants between 2020 and 2023 because it would be uneconomic to install the necessary environmental controls to bring them into compliance with federal regulations. These plants represented about 1,822 MW_{UCAP}[34] of capacity in 2017 (Dimitry Direct at 17.) DTE proposed to replace part of capacity through its Proposed Project, and the rest through other actions in its Proposed Plan.

[34] The unforced capacity (UCAP) of a generator is the "credit" that it receives towards resource adequacy requirements and is based on the historic performance of the unit.

Q. DOES DTE PARTICIPATE IN A REGIONAL WHOLESALE MARKET THAT IS RESPONSIBLE FOR MAINTAINING THE RELIABILITY OF THE BULK POWER GRID IN MICHIGAN?

A. Yes. DTE is a member of the Midcontinent Independent System Operator (MISO), which is the regional transmission operator (RTO) responsible for transmission planning and operating various wholesale electricity markets in Michigan and surrounding states.

Q. DOES MISO HAVE RULES FOR HOW POWER NEEDS ARE DETERMINED AND HOW THEY CAN BE MET?

A. Yes. As described by Witness Wojtowicz:

> The Company is required to develop a resource plan that complies with the reliability standards set forth by the North American Electric Reliability Corporation (NERC). NERC Standard BAL-502-RFC-02 "Planning Resource Adequacy Analysis, Assessment and Documentation" requires the Planning Coordinator to calculate a planning reserve margin for each planning year. MISO is the responsible Planning Coordinator for the Midcontinent ISO region. (Wojtowicz Direct at 6.)

As the planning coordinator responsible for maintaining the health of the bulk power grid that serves Michigan and surrounding states, MISO has created a set of rules and regulations that define how utilities in its footprint must meet their power needs to maintain the reliability of the grid.

MISO defines reliability through the concept of "resource adequacy." MISO's goal is "to support the achievement of resource adequacy i.e. ensure there is enough capacity available to meet the needs of all consumers in the MISO footprint during peak times and at just and reasonable rates."[35] The RTO-wide definition of resource adequacy is broken down into specific targets for MISO zones, each of which must have sufficient resources to meet its capacity obligation.[36] MISO defines the criteria that participating

[35] https://www.misoenergy.org/Planning/ResourceAdequacy/Pages/ResourceAdequacy.aspx

[36] DTE is part of MISO Zone 7, which includes the lower peninsula except for a small portion of southwest Michigan.

load serving entities such as DTE must adhere to in order to maintain the chance of a blackout from a lack of capacity resources to less than one day in ten years. This loss-of-load expectation (LOLE) is mathematically translated into a quantity of capacity in MW that each utility must secure, either through ownership or contract. This quantity is called the Planning Reserve Margin Requirement (PRMR).

DTE "is required to demonstrate compliance" that it has sufficient generation under its control, allowing for factors such as unexpected generator outages and line losses, to meet the PRMR as calculated by MISO. (Dimitry Direct at 16.) DTE can meet its capacity obligation through a number of resources, including energy efficiency, demand response, renewable energy facilities, and conventional generation. Each resource is assigned its own unforced capacity value. For dispatchable resources, this value is calculated based on its three-year historic forced outage rate. For wind and solar resources, it is based on the performance of the generator during hours when MISO's bulk power grid is likely to experience its highest load.[37]

Q. HAS DTE IDENTIFIED A CAPACITY SHORTFALL THAT COULD IMPACT ITS ABILITY TO MEET MISO'S RESOURCE ADEQUACY STANDARDS?

A. Yes. DTE plans to retire several coal plants between 2020 and 2023. Without these facilities, it projects a shortfall in meeting its MISO capacity obligation in 2022.

Q. WHAT HAS DTE PROPOSED TO FILL THIS RESOURCE ADAQUACY GAP?

A. It has filed its Proposed Plan in this CON, which includes the Proposed Project and represents DTE's recommendation on how to meet its MISO capacity obligations.

[37] Non-wind resources are based on performance between 2 and 5 PM from June to August, while wind resources are credited based on their performance during the highest 8 peak hours of the summer.

Q. WHAT IS DTE'S DEFINITION OF THE INTENDED FUNCTION OF THE PROPOSED PROJECT?

A. DTE's definition of the intended function of the Proposed Project is to "supply energy to the grid when dispatched." (ELPCDE-3.12b, Ex. ELP-3 (KL-3) and ELPCDE-7.4f., Ex. ELP-4 (KL-4))

Q. IS DTE'S OBLIGATION TO CONSTRUCT A FACILITY THAT IS ABLE TO "SUPPLY ENERGY TO THE GRID WHEN DISPATCHED," OR TO MEET ITS MISO RESOURCE ADEQUACY REQUIREMENTS?

A. It is the latter. DTE's obligation to reliably serve the expected load of its customers is captured in meeting its MISO's resource adequacy requirements. The way in which it chooses to do so is not explicitly prescribed either by the underlying CON statute or by MISO. In fact, MISO allows many resources to count towards DTE's capacity obligations, including, but not limited to, energy efficiency, demand response, imported energy, and renewable generation. DTE's definition of the intended function of the Proposed Project is a critical mistake called a "category error."

Q. WHAT IS A CATEGORY ERROR?

A. A category error is a logical fallacy where one erroneously ascribes properties to an object or idea, and then makes conclusions based on those same erroneous properties. In this case, DTE assumes that the only reliable plant is one that can supply energy to the grid when dispatched. It then concludes that any other portfolio (such as one anchored by distributed renewable resources) that doesn't also contain this property cannot be a reliable plant. However, MISO's reliability requirements do not require that capacity resources be dispatchable, exposing the flaw in DTE's reasoning.

Q. DOES DTE BELIEVE THAT A DIVERSE FLEET OF GEOGRAPHICALLY DISTRIBUTED RENEWABLE RESOURCES CAN ALSO MEET ITS STIPULATED FUNCTION OF THE PROPOSED PROJECT?

A. No. In this CON proceeding, DTE has advanced the Proposed Project as its preferred mechanism for meeting its MISO resource adequacy requirements, while simultaneously dismissing out of hand that a portfolio based on distributed renewable energy projects could meet this same purpose. Because of the category error discussed above, DTE believes that because renewable resources such as solar and wind cannot be dispatched, it follows that a "distributed fleet of [] distributed solar and wind systems cannot meet the intended purpose of the Proposed Project". (ELPCDE-7.4f, Ex. ELP-4 (KL-4))

Q. DOES DTE ELABORATE ON WHAT MIGHT BE NEEDED FOR A DISTRIBUTED PORTFOLIO OF RENEWABLE GENERATORS TO MEET ITS DEFINITION OF THE PURPOSE OF THE PROPOSED PROJECT?

A. Yes. It states that "[f]or renewable capacity to be considered 'reliable,' additional firming capacity assets (generally natural gas engines, combustion turbines or extended battery) need to be installed." (ELPCDE-3.12b, Ex. ELP-3 (KL-3)) This again is consistent with its erroneous assumption that the only reliable plant is one that can be dispatched.

Q. ARE THESE RESTRICTIONS CONSISTENT WITH MISO'S DEFINITION OF CAPACITY RESOURCES?

A. Not at all. As admitted by DTE itself, MISO does not require that solar or wind resources be "backed up" in order to receive capacity credit. (ELPCDE-7.4b, Ex. ELP-5 (KL-5)) While solar and wind do receive less than their nameplate capacity when their capacity contribution is calculated, there is no obligation to pair solar and wind projects with combustion turbines, gas engines, or batteries to get this credit.

DTE's obligation is to meet MISO's resource adaquecy requirement as expressed through its PRMR. To suggest that it can only meet this requirement by building a facility that "can supply energy to the grid when dispatched" conflates the operating characteristics of the Proposed Project with the underlying obligation of DTE to meet its capacity needs in a classic logical fallacy.

Q. DOES CONSTRUCTING A SINGLE, CENTRALIZED FACILITY SUCH AS THE PROPOSED PROJECT GUARANTEE THAT THE CAPACITY RESOURCE WILL BE AVAILABLE WHEN MISO'S SYSTEM PEAKS?

A. No. Notwithstanding the flaw in its logic regarding reliable plants, DTE acknowledges that a single incident can take the entire 1,100 MW Proposed Project offline during hot summer afternoons when MISO's system is most likely to peak. (ELPCDE-7.4d, Ex. ELP-6 (KL-6)) It also acknowledges that the Proposed Project is anticipated to be unexpectedly out of service for 331 hours, or nearly 14 days, every year. (ELPCDE-7.4e, Ex. ELP-7 (KL-7)) Given that DTE believes it imprudent to rely on more than 300 MW of market purchases to meet its capacity obligation, if just one of these unplanned outage hours falls on a peak afternoon, DTE's ability to serve its load will be greatly diminished.

Q. DOES A PORTFOLIO OF DISTRIBUTED ASSETS THAT PROVIDES THE EQUIVALENT AMOUNT OF CAPACITY AS THE PROPOSED PROJECT FACE THE SAME OPERATIONAL RISK THAT THE ENTIRE FLEET OF GENERATORS WILL BE UNAVAILABLE AT THE SAME TIME?

A. No. By its nature, distributed assets are smaller and more numerous. Unplanned outages are independent events, so if one facility is offline due to equipment failure, it will not affect another facility's likelihood of experiencing an equipment failure. Imagine a portfolio of 110 20 MW solar projects, each of which contributes 10 MW towards DTE's capacity obligation and equals the 1,100 MW of the Proposed Project. Even if each facility had the same expected outage rate as the Proposed Project (that is, 331 hours per year or 3.78%), the chances that more than 10 plants will be out of service simultaneously is only 0.9%, while the chances that more than 15 plants will be out of service simultaneously is only 0.002%.[38] In other words, a distributed fleet with the same expected outage rate as the Proposed Project would be virtually assured to have at least 950 MW of its 1,100 MW operating at all times, while the Proposed Project can be expected to be entirely offline an equivalent of 14 random days a year.

Q. ARE THERE OTHER SITUATIONS IN WHICH A DISTRIBUTED PORTFOLIO OF ASSETS MIGHT NOT PRODUCE THEIR MAXIMUM OUTPUT?

A. Yes. As solar resources only produce energy during the day and wind resource only produce energy when there is sufficient wind, there will be times when some portion of the renewable resources will be producing less than their maximum output. However, this reality is already factored in through MISO's resource adequacy methodology. Solar and wind projects are not credited with 100% of nameplate capacity for resource adequacy reasons. Solar is initially discounted to 50% and then updated based on actual performance. Wind sees a sharper cut, earning only 12.6% of nameplate capacity. This discount is already factored in to the calculation.

Q. DID DTE SUGGEST MORE HYPOTHETICAL SITUATIONS WHEN A PORTFOLIO OF DISTRIBUTED RENEWABLE ASSETS COULD OPERATE BELOW THEIR EXPECTED LEVELS?

A. Yes, although the examples its proffered are highly unlikely to correspond to conditions that will produce near-peak demand conditions. DTE suggested that "generation of solar plants will be significantly impacted during the MISO peak hours by cloud cover or thunderstorms" and that "generation capability of wind plants are [sic] variable and not predictable during the MISO peak hours when wind velocity may or may not be at the

[38] This can be modeled through the binomial distribution in Excel.

condition required to allow the wind turbine to operate at rated load capability." (ELPCDE-7.4f Supplemental, Ex. ELP-8 (KL-8))

While these answers might be correct for a single facility, one of the primary benefits of a geographically distributed portfolio is that weather conditions vary from place to place. If a cloud covers one solar plant, another one miles away might be generating at full capacity. And in any instance when the entire fleet is under cloud cover or experiencing a thunderstorm, then it is highly unlikely that Zone 7 will be experiencing peak load conditions as summer peaks are driven by hot, sunny afternoons (during which, of course, solar PV will be operating at or near peak output). Likewise, wind output is lower during summer afternoons, but this is already factored in by only crediting wind with 12.6% of its rated load capability.

DTE's Integrated Resource Plan and Proposed Plan

Q. PLEASE DESCRIBE THE HIGH-LEVEL RESULTS OF DTE'S 2017 IRP AND PROPOSED PLAN.

A. DTE's Proposed Plan includes closing several coal-fired power plants between now and 2023 rather than pay the uneconomic costs of upgrading the facilities to meet environmental compliance regulations. It is also proposing to increase its energy efficiency programs to aim for an annual 1.5% of sales reduction and grow its demand response programs by 125 MW. DTE proposes to add 60 MW_{DC}[39] of solar and 686 MW of wind to meet PA 342, in addition to upgrading its pumped storage facility to increase its output by 227 MW. Additionally, DTE proposes to construct the Proposed Project, a roughly 1,100 MW nameplate facility to be fully online in 2023. The balance of capacity needs is comprised of up to 300 MW of market purchases per year. (IRP Report at 26).

[39] I will refer to solar capacity in terms of nameplate or MW_{DC} capacity, while other technologies will be assumed to be MW_{AC} even as they are designated MW. DTE used a 1.2 AC/DC ratio to convert between the nameplate and inverter rating of solar systems.

Although DTE's Proposed Plan includes some positive elements (such as closing its coal plants and expanding its pumped hydro facilities), these do not outweigh the failure of DTE to adequately consider alternatives to the Proposed Project, nor do they excuse the faulty assumptions upon which DTE relies.

Q. DID YOU ENCOUNTER ANY DIFFICULTY EVALUATING DTE'S IRP?

A. Yes. There were multiple modeling tools that were used, often with differing inputs. The standard output from the Strategist model was provided in a very user-unfriendly text document format that made subsequent analysis and comparison between scenarios very difficult. Additionally, the nomenclature and abbreviations used in these reports were not transparent and required additional discovery to decode.

DTE's handling of energy efficiency was particularly challenging to decipher. DTE had commissioned two potential studies from the consulting firm GDS Associates, Inc., – one for energy efficiency and one for demand response – but the results of those studies were not directly incorporated into the IRP. Further, DTE attempted to 'unbundle' the energy efficiency savings embedded in its base forecast to allow it to create sensitivities with greater or lesser savings. It was quite difficult to reconcile these forecasts across the multiple reports, models, and years.

Renewable energy inputs varied substantially between uses. No less than six distinct projections for solar and wind prices were used, and those included different assumptions for core values such as inflation. Some forecasts went through 2025, some through 2035, and some through 2040. Some values were consistent between models, while some differed. Comparing a critical data element – price forecasts for renewable technologies – across occurrences in the IRP was challenging at best.

Finally, while the majority of the IRP focused on and utilized data from its pre-2017 update, the 2017 update introduced several critical changes. Energy efficiency was increased, fuel prices changed, renewable energy inputs were modified – in some cases considerably so – and a new low-carbon scenario was partially introduced. These new assumptions dropped the projected net present value of the revenue requirement (a proxy for cost) of the Proposed Plan under the reference scenario from $15.7 billion to $13.6 billion, a 13.5% drop. (Exhibit A-10 at 6.) Despite this, DTE did not re-analyze any of the original scenarios and sensitivities other than the Reference case under the new input assumptions, making it impossible to determine if the models would have performed differently.

Q. PUTTING ASIDE THE FUNDAMENTAL ISSUE OF DTE IGNORING THE POTENTIAL FOR A DISTRIBUTED PORTFOLIO TO MEET IS RESOURCE ADAQUECY NEEDS, PLEASE DESCRIBE THE AREAS OF CONCERN YOU HAVE WITH DTE'S IRP ASSUMPTIONS THAT ARE RELEVANT TO YOUR TESTIMONY.

A. The remainder of this section focuses on four areas of the IRP process where I believe that DTE's assumptions warrant substantial scrutiny. The first is DTE's renewable energy assumptions, with a particular focus on solar energy. The second is DTE's assumptions on energy efficiency (EE) and demand response (DR) that were integral to determining the load forecast. The third is the 2017 refresh of the IRP along with an updated scenario designed to be consistent with DTE's recently announced long-term GHG emission reduction goals. The final is DTE's presentation of the financial benefits of selecting the Proposed Project over a "no build" option. I will expand on each of these topics in the subsections below.

IRP Renewable Energy Assumptions

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. In this subsection, I will discuss DTE's renewable energy assumptions used in its IRP. I focus on solar and wind capital costs, solar operations and maintenance (O&M) costs, and solar deployment assumptions, and show how DTE's assumptions fare poorly when compared with other publicly available sources. I also critique DTE's choice to model only south-facing, fixed-tilt PV systems, when single-axis tracking systems are taking over the industry and offer far superior performance. Finally, I question why DTE fails to deploy substantial solar and wind resources in time to take advantage of expiring or reducing federal tax credits.

DTE's Solar and Wind Capital and O&M Costs are Too High

Q. WHAT ASSUMPTIONS DOES DTE MAKE ABOUT RENEWABLE ENERGY COSTS IN ITS IRP?

A. DTE makes assumptions about renewable energy capital costs and operating and maintenance (O&M) costs in multiple places within its IRP. These include assumptions about the price of solar and wind technologies as well as deployment assumptions. While DTE also considers landfill gas and biomass technologies, my testimony will focus on solar and wind.

DTE's IRP contains at least seven different technology price forecasts for capital costs in various scenarios and sensitivities. DTE does not explain why there are so many different forecasts for the same core values, or why it used different assumptions in different models. DTE's solar and wind forecasts are presented in Figures 7 and 8 below, which I created using the data made available by DTE in its workpapers, adjusted to nominal dollars per kW_{DC} for the Michigan region.

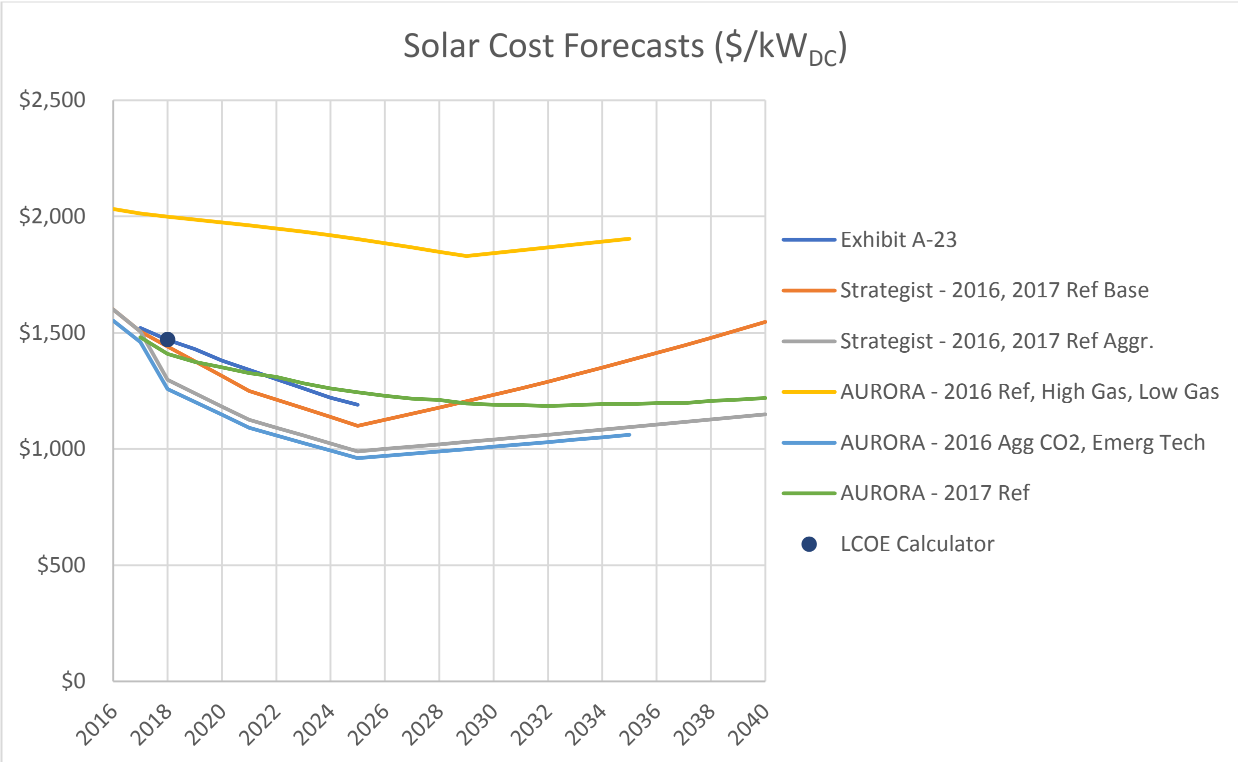

Figure 7 - Solar Cost Forecasts

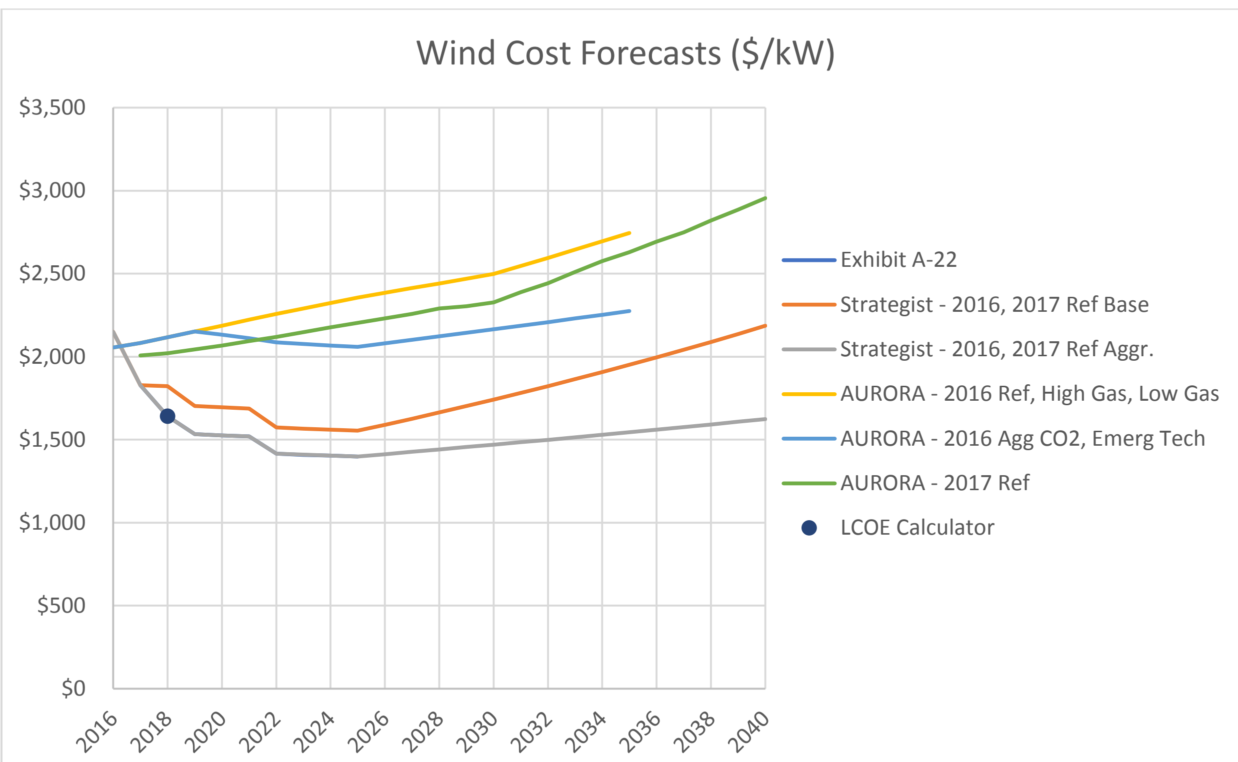

Figure 8 - Wind Cost Forecasts

Q. WHAT IS THE EXHIBIT A-23 FORECAST?

A. Exhibit A-23 data was taken from a Navigant Consulting report that was about state projections for distributed energy systems. (ELPCDE-3.2u, Ex. ELP-9 (KL-9)) The Navigant data is different from both the Strategist and PACE inputs, and only continues through 2025. [redacted] My analysis shows that Exhibit A-23 data from the Navigant black-box forecast simply [redacted] and yet this was the most prominent price projection in DTE's IRP report.

Q. CAN YOU DESCRIBE THE STRATEGIST SOLAR CAPITAL COST FORECASTS?

A. Given that DTE could not rely totally on the Navigant figures (as they only went through 2025), it needed to produce alternative forecasts to fully model solar through the analysis period. While it appears that the 2016 Strategist[40] Base Case follows a similar trajectory as the Navigant figures, there is not a consistent relationship between annual data points. While the Navigant figures presented in Exhibit A-23 dropped prices 3% per year, the 2016 Strategist Base Case assumes a flat dollar reduction of $63.75/kW per year from 2017 to 2021, followed by a $37.50/kW reduction from 2021 to 2025. There is no justification or source provided for these figures. (WP KJC-48.)

After decreasing in nominal terms between 3% and 5% per year (roughly 5.5% to 7.5% per year in real dollars) for eight years, DTE assumes that prices will reverse. From 2026 and beyond, it assumes a constant escalator of 2.3%, a value consistent with inflation expectations. In other words, after falling at a CAGR of -4.1% for a decade

[40] Strategist is one of the models that DTE used in its IRP. This model focuses on meeting capacity obligations in DTE's territory.

between 2016 and 2025, DTE expects solar prices to suddenly increase 2.3% in 2026 and beyond. There is no discussion of what type of shock could cause a price forecast to swing that much.

Q. CAN YOU DESCRIBE THE AURORA SOLAR CAPITAL COST FORECASTS?

A. The AURORA[41] 2016 Reference, High Gas, and Low Gas solar projection is 40%-70% higher than the Strategist 2016 Reference Base Solar forecast, while the AURORA 2016 Aggressive CO2 and Emerging Tech forecast is nearly identical to the Strategist 2016 Reference Aggressive Solar forecast[42]. There appears to be no consistency between the Strategist and AURORA solar price forecasts either.

The 2016 solar forecasts tend to show price declines through 2025 or 2029, and then increase at various rates. However, the 2017 AURORA update declines steadily on a constant dollar basis, only increasing in nominal dollars after 2033 due to higher inflation assumptions embedded in the 2017 AURORA update. The only totally consistent data point is the single 2018 value that the LCOE Calculator and Exhibit A-23 share.

Q. WHAT ABOUT THE WIND FORECASTS THAT DTE USED?

A. The wind forecasts are not much more consistent. Again, the 2016 Reference Base Wind case forecasts diverge, while 2016 Aggressive Wind cases match perfectly. The 2017 AURORA update trends between the 2016 AURORA Reference and 2016 AURORA Aggressive forecasts, but hews closer to the 2016 Reference than does the solar forecast. It should be noted that the lowest forecast of the group – the Strategist 2016 Reference Aggressive Wind price – is the one listed in the actual IRP document. (IRP Report at 124). The higher cost forecasts are not called out.

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[41] The AURORA model is also used in DTE's IRP. It is broader in geographic scope that Strategist, analyzing the PJM-MISO region.

[42] The difference appears to be the lack of application of the AURORA RFCM scaler to the Strategist inputs used to translate nationwide costs to region-specific costs.

Neither the solar nor wind price forecasts were updated for the 2017 Strategist update. Given how substantially AURORA's 2017 solar estimates fell, it is unclear why DTE did not take the opportunity to update prices in the fast-moving solar market.

Q. HOW DO THESE CAPITAL COST FORECASTS COMPARE TO OTHER AVAILABLE FORECASTS?

A. They differ both in scale and trajectory. DTE's assumptions used in the bulk of the modeling date to early 2016 at the most recent. Solar prices in particular have fallen quickly, often outpacing previous forecasts. This is evident in the 2017 reference scenario in DTE's own AURORA forecasts, which both fell and flattened from the 2016 version.

With the exception of the 2017 AURORA reference forecast (which was not used for the bulk of DTE's IRP), all of DTE's forecasts are overly simplistic, either increasing or falling a fixed dollar or fixed percentage from year-to-year. There is no underlying documentation supporting the changes; they simply appear in the workpapers.

By contrast, Mr. Beach developed an alternative price forecast based on a combination of system-level data from Greentech Media (GTM) and EPC-based costs from Lawrence Berkeley National Lab (LBNL) and created a sensitivity based on potential actions of the IntTC case discussed previously. Mr. Beach explains the derivation of his forecast in his testimony. This forecast is robustly supported by using data from nationally recognized entities and the underlying data is publicly available. Mr. Beach's forecasts for fixed-tilt systems forecast is combined with a subset of DTE IRP forecasts and the two most recent values from the Lazard LCOE report (which do not include any impact from the trade case)[43] in Figure 9 below.

[43] Version 10 (2017): https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf
Version 11 (2018): https://www.lazard.com/media/450337/lazard-levelized-cost-of-energy-version-110.pdf

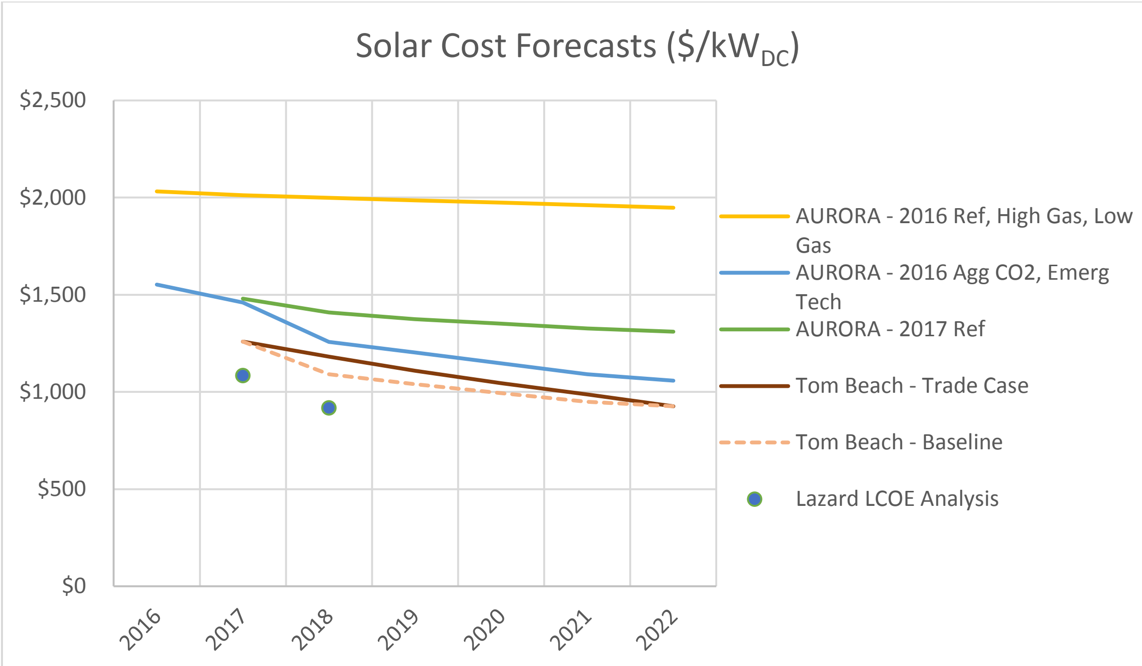

Figure 9 - Solar Cost Forecast with Tom Beach

Mr. Beach's forecast, based on heavily researched data from GTM Research, is substantially below even the most aggressive pricing scenario that DTE modeled. The 2016 Reference case is 69% higher than Mr. Beach's Trade Case forecast in 2018, and the gap widens further by 2022, where the 2016 Reference case is more than twice as high as that of Mr. Beach. When compared to the updated 2017 Reference case, DTE is still using figures that are between 20% and 40% higher than Mr. Beach's. Even the most aggressive cost forecast in DTE's IRP – used only in some sensitivity runs – retains a roughly 7-14% premium over Mr. Beach's updated forecast, even after accounting for potential tariffs.

DTE's choice to run the IRP with the high-cost renewable assumptions in its 2016 scenarios and sensitivities increased the cost of scenarios with higher levels of solar deployment compared to other alternatives. However, as explained in more detail in Mr. Beach's testimony, using a more realistic projection for solar prices can make a substantial difference in the cost-effectiveness of solar resources.

Q. WHAT FORECAST WOULD YOU RECOMMEND?

A. I would strongly recommend Mr. Beach's forecast over the various ones that DTE uses. DTE's Strategist forecasts lack any degree of rigor. Simply subtracting a constant dollar/kW figure in consecutive years is rudimentary at best. The 2016 AURORA figures are essentially identical to the Strategist forecast but without a regional cost escalator. The 2017 AURORA forecast appears to be somewhat more robust (that is, it does not simply subtract a fixed dollar or percentage cost year-to-year), but this forecast was barely used in the IRP, applying only to the 2017 Reference scenario.

Mr. Beach's forecast is based on GTM Research's forecast. GTM Research is an industry leader with unparalleled access to solar component costs data. GTM builds up its forecasts based on component-level cost data for residential, commercial, and utility sectors. It includes estimates of soft costs broken down into many categories such as design and engineering, permitting and interconnection, and taxes. The resulting forecast is based on fundamentals, not a generic drop in the total cost.

Q. DID YOU ALSO EXAMINE DTE'S SOLAR O&M COST ASSUMPTIONS?

A. Yes. As with the capital cost projections, DTE uses different values for solar operating and maintenance (O&M) costs. Two main values are found in the various projections: $12/kW-year and $23/kW-year.

The $12/kW-year value is from the December 2016 Lazard LCOE report, "Levelized Cost Energy Analysis 10.0."[44] (ELPCDE-1.32, Ex. ELP-10 (KL-10)) However, in the Lazard LCOE report, the $12/kW-year figure is found in the left column of page 18. As indicated in Footnote c on page 18 of the above referenced report, the left column "represents the assumptions used to calculate the low end LCOE for single-axis tracking." The value in the right column of the same report is $9/kW-year, which per the

[44] Available at https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf

same footnote "represents the assumptions used to calculate the high end LCOE for fixed-tilt design." Given that DTE has modeled only fixed-tilt designs, it has selected the wrong value from the Lazard LCOE report and should be using $9/kW-year for the O&M cost.

The $23/kW-year value comes from Exhibit A-37, the HDR Engineering report "IRP Supply and Demand-Side Alternatives Analysis Study." Pages 96 through 99 of this report contain some limited detail about this figure, but not enough to fully understand what costs are included. HDR assumes that a full-time salaried staff person making $96,000 per year will be tasked to this project, representing about $4.80/kW-year of the identified $23/kW-year. However, this accounts for barely 20% of the fixed costs. HDR provides no additional details on this figure in the report.

Q. DID DTE HAVE ANY RESPONSES WHEN ASKED ABOUT THESE VALUES?

A. Yes, although they were not convincing. When asked about the selection of the $12/kW-year value from the Lazard LCOE report, DTE responded that the "$12/kW-year estimate is a proxy for O&M in the absence of Michigan-specific, annualized, fixed-tilt utility-scale O&M cost data to reference." (ELPCDE 4.2c, Ex. ELP-11 (KL-11)) In other words, rather than using the value from the report that clearly relates to a fixed-tilt system, as it initially indicated in ELPCDE-1.32, Ex. ELP-10 (KL-10), it now states that the 33% markup – that coincidently results in the higher of the two O&M values in the Lazard report – is due to regional differences between the default Lazard system and a Michigan-specific system. There is no supporting detail behind this answer, no analysis of what factors might drive substantially higher O&M costs in Michigan, and no way to reconcile DTE's two discovery responses.

When asked about the HDR report, DTE again skirted the issue. Despite having been asked for a detailed accounting of what made up the $23/kW-year fixed O&M cost, DTE stated that the non-personnel cost represents "18,211 $/MW toward fixed O&M costs." (ELPCDE-7.6b, Ex. ELP-12 (KL-12)) This non-answer demonstrates the lack of justification for this figure. Further, it was the higher $23/kW-year, not the lower $12/kW-year, figure that was used for all new solar in all Strategists runs. (MECNRDCSCDE-9.6a, Ex. ELP-13 (KL-13))

Q. DID YOU QUANTIFY THE IMPACT OF THIS CHANGE?

A. Yes. Using DTE's LCOE calculator in WP KJC-479 along with Mr. Beach's 2018 trade case sensitivity capital cost of $1,181/kW, but leaving all of DTE's other assumptions in place, Table 1 below shows the impact of the different O&M rates on the final LCOE.

O&M ($/kW-year)	Levelized O&M ($/MWh)	LCOE ($/MWh)	Increase
$9.00	$6.80	$79.21	
$12.00	$9.07	$81.47	2.9%
$23.00	$17.40	$89.79	13.4%

Table 1 - Impact of Solar O&M Costs on LCOE

The increase from $9 to $12 produces a noticeable impact of 2.9%, but moving from $9 to $23 produces a stark increase of 13.4% in the LCOE. Given the impact that this figure can have on the economics of solar, DTE's questionable support for its underlying numbers is problematic.

There is also reason to believe that even these LCOEs are higher than what DTE could get by signing PPAs on the market. As discussed further in my testimony, recent PPAs have been signed in other parts of the country with prices much lower than those found in Table 1. By taking advantage of the competitive market, DTE might be able to secure solar resources for less than building its own.

Q. WHAT DO YOU CONCLUDE ABOUT DTE'S SOLAR O&M ASSUMPTIONS?

A. They are overstated. DTE selected the incorrect value from the Lazard report, and the $12/kW-year figure should actually be 25% lower at $9/kW-year. If DTE intended to increase this figure to account for regional differences, it provided no support for this choice. The HDR value is more than 150% higher than Lazard's figure, and HDR provides no support for the figures behind its report's calculation. Given that O&M

makes up a sizable portion of the total costs in DTE's forecasts and is escalated over time, this mistake adds up.

DTE's Renewable Energy Deployment Forecasts are Too Low

Q. PLEASE DESCRIBE THE IRP'S RENEWABLE ENERGY DEPLOYMENT ASSUMPTIONS.

A. Just as there are multiple forecasts for solar and wind prices, there are multiple forecasts for solar and wind deployment. DTE projected four different deployment forecasts for wind and solar: one each for the 2016 and 2017 Reference case, one for the 2016 High Renewables sensitivity, and one for the 2017 75% CO2 Reduction by 2040 scenario. The solar and wind projects were added exogenously to the model based on DTE's specified schedule. The cumulative installations are shown below in Figures 10 and 11.

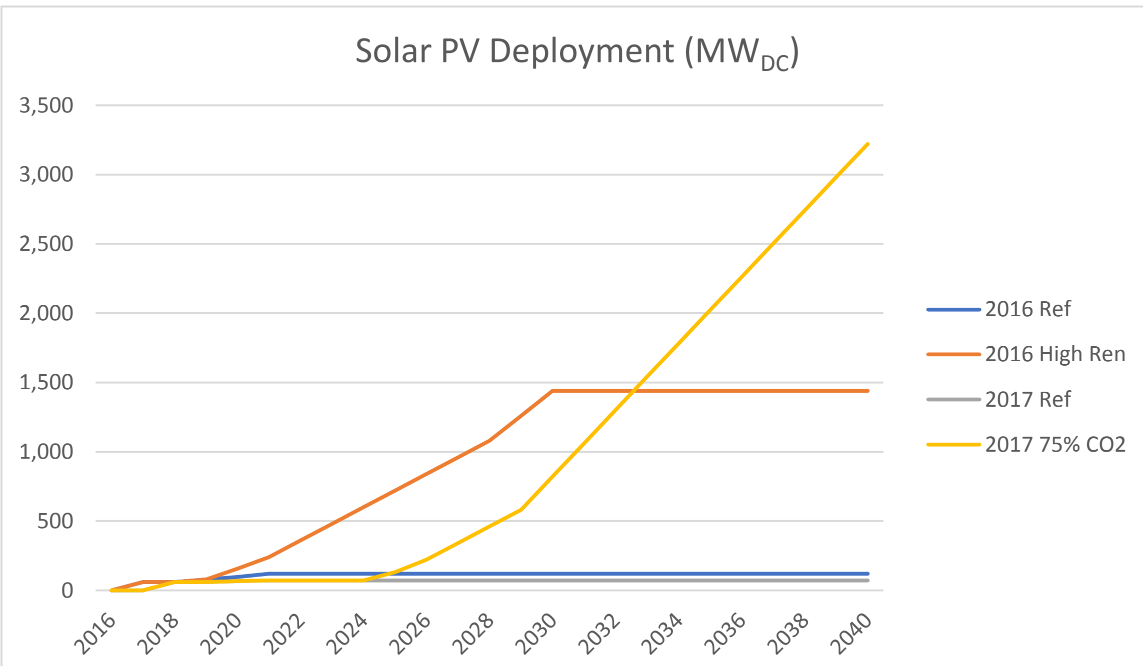

Figure 10 - Solar PV Deployment Forecast

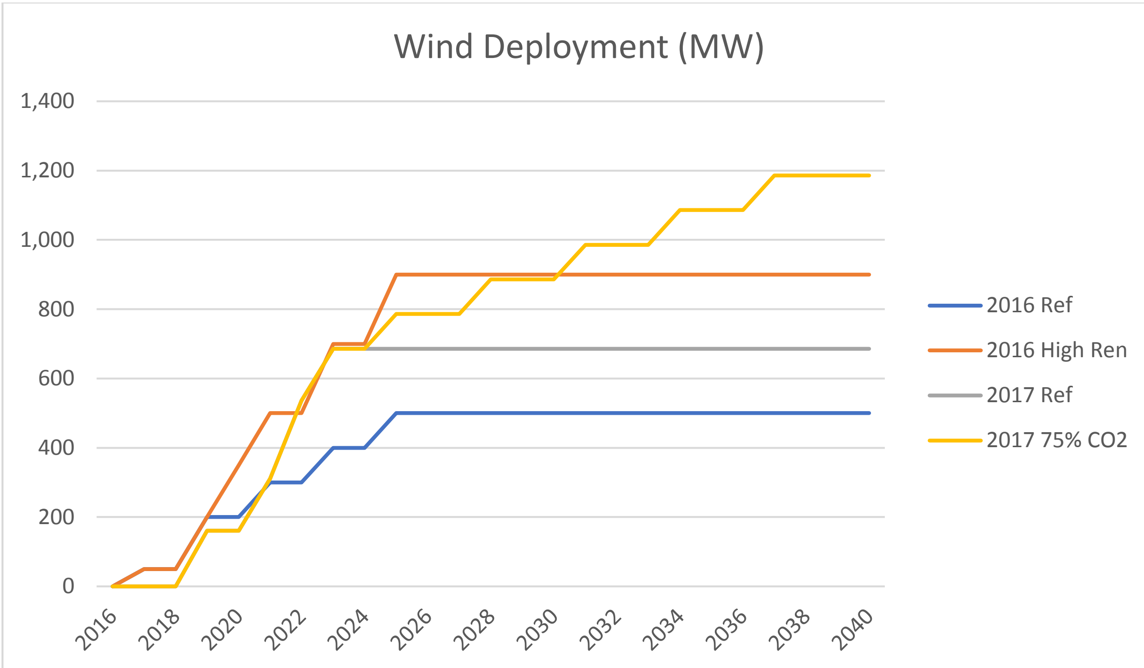

Figure 11 - Wind Deployment Forecast

Solar deployment in the two Reference cases is barely distinguishable on the chart. The 2016 Reference scenario included 120 MW_{DC} to be installed by 2021, at which point deployment is halted. The 2017 Reference scenario actually reduced this figure further, adding only 72 MW_{DC} by 2021 and holding steady thereafter. The High Renewable build is more aggressive than the Reference case, with DTE deploying 1,440 MW_{DC} through 2030 before halting. Only in the 2017 75% CO2 Reduction scenario does DTE assume that solar will continue throughout the projected period, steadily increasing until just over 3,300 MW_{DC} is installed by 2040.

The wind deployment forecasts do not show as much disparity between the Reference cases and the sensitivities. The 2016 Reference includes the lowest wind forecast, with DTE staggering installations every other year until reaching 500 MW total in 2023. The 2017 Reference scenario increases project size and adds an additional installation in 2022, culminating in 686 MW by 2023. In the High Renewable sensitivity, DTE adds more projects still through 2025, topping out at 900 MW. Again, only the

2017 75% CO2 Reduction scenario does DTE continue to add projects through 2040, reaching an ultimate value of 1,186 MW of wind.

Q. DOES DTE HAVE SEPARATE DISTRIBUTED SOLAR PROJECTIONS?

A. Yes. While the majority of the renewable build it assumed to be utility-scale projects, DTE did project distributed solar projects. DTE does not specifically model these facilities, but rather assumes a reduction in energy use that corresponds to the output of distributed generation solar. In its 2016 cases, DTE assumes an additional 3 GWh of DG solar production per year, equal to the output of roughly 2.5 MW of new DG solar annually. However, this assumption is only embedded in the Low Load sensitivities, not the Reference case or the High Load sensitivity. (ELPCDE-5.38, Ex. ELP-14 (KL-14)) In its 2017 case, DTE's projections are in Figure 12 below and show a ramp up from less than 1 MW annually in recent years to between 10 and 12 MW between 2019 and 2024, before tapering off again in 2027 and beyond. (ELPCDE-3.2n, Ex. ELP-15 (KL-15)) DTE assumed no acceleration beyond what was provided in these data requests, and noted that "the capacity associated with solar adoption was not determined." (ELPCDE-3.2o, Ex. ELP-16 (KL-16))

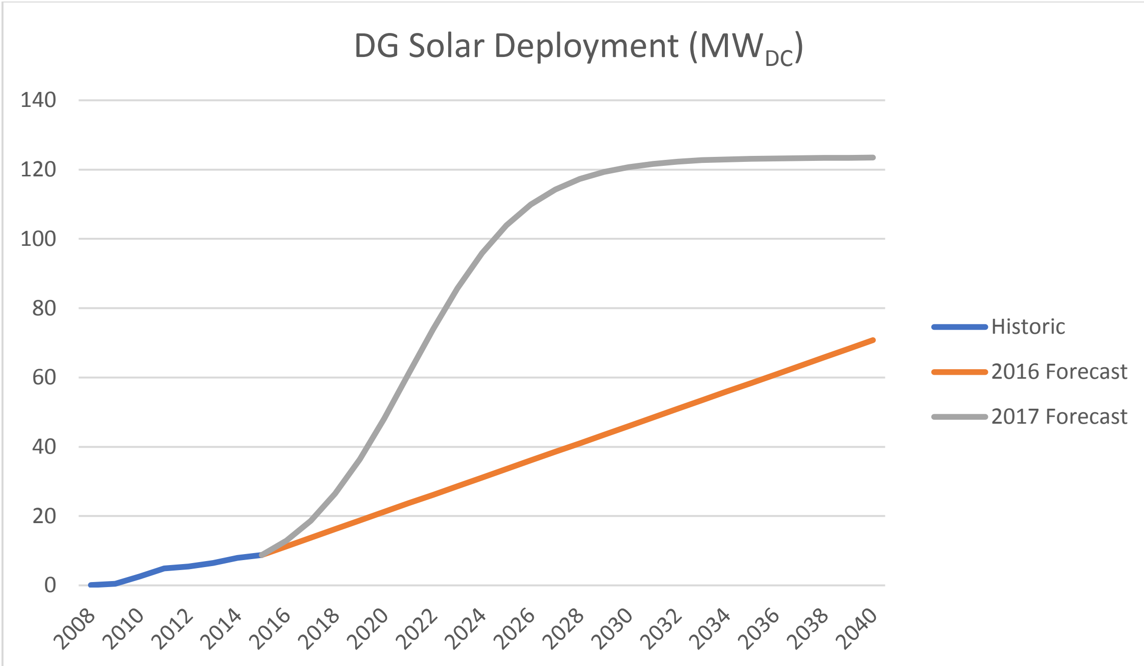

Figure 12 - DG Solar Deployment

Q. HAVE YOU FORMED AN OPINION ABOUT TO THE SOLAR DEPLOYMENT PROJECTIONS?

A. In my opinion, the solar PV projections in the two Reference cases are well past conservative and simply cannot be reconciled with trends in the market. As discussed earlier in my testimony, solar PV has seen massive declines in prices in the past decade, and these decreases are projected to continue well into the future. Commercial entities are increasingly installing and purchasing zero-carbon energy.[45] Solar PV is winning competitive procurements, even outside the sunniest parts of the country.[46] DTE makes no allowance for an increase in PURPA projects, and does not even factor distributed generation into its 2016 Reference case scenarios. To suggest that no more than 72 MW_{DC} of utility-scale PV will be added in the next 23 years runs counter to all of these trends and is simply not reasonable.

[45] https://www.greentechmedia.com/articles/read/the-latest-trends-in-corporate-renewable-energy-procurement
[46] http://www.rechargenews.com/solar/1184639/solar-emerges-as-winner-in-new-england-clean-energy-rfp

While the High Renewables scenario deploys more solar than the Reference case, it continues to understate the ability to bring on solar in the near term. The solar market has shifted radically in the past five years, both in terms of pricing and deployment. DTE does not pursue anything resembling an aggressive near-term build strategy to take advantage of available tax credits. As has been seen in other states, and as is indicated by the MISO interconnection queue for Michigan, a substantial amount of solar is in various stages of development today that can be deployed in coming years.

The 75% CO2 Reduction sensitivity is the most aggressive when compared to DTE's other scenarios, but it still suffers from timing and scale timidity. But while 3,322 MW_{DC} seems like a large figure, it is by no means unattainable or unreasonable for Michigan. According to the GTM Research data, eleven states are projected to exceed 3,322 MW_{DC} by 2022, while six states are projected to add at least 3,322 MW_{DC} between 2017 and 2022.[47] And even in its most aggressive scenario, DTE continues to exclude aggressive near-term builds and pending PURPA and DG projects, consistent with its misguided concept of the contribution distributed resources can make.

Q. YOU MENTIONED THE MISO INTERCONNECTION QUEUE. WHY IS THAT RELEVANT HERE?

A. The MISO Interconnection Queue maintains a list of projects that have filed an application to interconnect a generating facility to the transmission grid managed by MISO.[48] A project must complete a number of studies before it is given permission to interconnect. MISO maintains a database of projects in the queue and provides a high-level status of their progress.

At the end of November 2017, the MISO queue contains 16 active solar PV projects in Michigan representing 2,093 MW (or, using DTE's 1.2 DC/AC ratio, 2,512

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[47] GTM Research U.S. Solar Market Insight for Q3 2017, GTM Research.
[48] https://www.misoenergy.org/Planning/GeneratorInterconnection/Pages/InterconnectionQueue.aspx

MW_{DC}) of capacity with an online date before the end of 2020. It also contains 21 active wind projects in Michigan representing 2,838 MW of capacity with an online date before the end of 2020.[49]

The interconnection queue is very relevant to this proceeding in two ways. First, DTE is attempting to convince stakeholders that to meet its capacity needs, it must build a large generating station in MISO Zone 7 (i.e. Michigan) because it states that it cannot count on sufficient imports from surrounding regions. But as the projects on the interconnection queue are built, they will increase the Zone 7 capacity resources, reducing the need for a large centralized plant to meet the zonal capacity requirements. DTE can utilize this capacity resource through a PPA, or even through a direct purchase of the project.

Second, the magnitude of the queue indicates that developers are ready and willing to commit funding to solar projects in Michigan. DTE's tepid deployment assumptions are based in part on its perceived inability to quickly construct new solar projects. However, there are thousands of MW of projects already under various stages of development that can be brought on well before the assumed build schedule found in DTE's IRP.

Q. WILL ALL OF THE PROJECTS CURRENTLY IN THE QUEUE BE COMPLETED?

A. No, not all of these projects will be completed as many developers withdraw their interconnection application before completing the project. However, about 25% of solar MW and 28% of wind MW from projects located in Michigan that were added to the queue with in-service dates through the end of 2016 were completed.[50] If these ratios

[49] 147 MW of PV and 730 MW of wind did not have an online date, but no project submitted after these had an in service date past 9/2020.

[50] 101 of 396 MW of PV projects and 2,795 of 10,151 with listed in-service dates through 12/31/2016 are marked "Done". The remainder are marked "Inactive".

were applied to the projects in the queue today that have in-service dates between 2017 and 2020, then one might expect approximately 533 MW (or 640 MW_{DC}) of the queued solar projects and 726 MW of queued wind would be installed in Michigan by the end of 2020. This figure does not include any additional projects that may enter the queue in the future.

Further, these installations are all based on projects that have been in the interconnection queue since at least June 2017. As such, these projects likely predate any influence from either DTE's IRP proposal or the recently announced Commission decision on PURPA. Not only that, but they are presumably further along in the development phase than a project just starting today and will be more likely to be in commercial operation inside the window of a project started by DTE under this IRP.

Q. DOES THE MISO QUEUE INCLUDE SMALLER PV PROJECTS THAT WILL BE INTERCONNECTION AT THE DISTRIBUTION SYSTEM LEVEL?

A. No. The interconnection queue is only for projects that will be connected to the MISO transmission system. Smaller projects, such as 2 MW PURPA projects and rooftop distributed generation systems, do not need to file a MISO interconnection request. Rather, the interconnection for these systems is handled at the local utility.

DTE provided a list of projects in its interconnection queue in ELPCDE 11.18, Ex. ELP-17 (KL-17). There are more than 131 solar projects at various stages of review, representing 635 MW of capacity.[51] 101 of these projects are exactly 2 MW in size, strongly suggesting PURPA projects. Further, about 85% of the 2 MW projects were added after the Commission's July 31, 2017, Order in DTE's avoided cost case that settled many of the outstanding methodology issues.[52]

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[51] Values show are from the lower "Applied for (KW)" figures. It is unclear whether these are AC or DC ratings, given that the "KVA" rating typically associated with AC capacity is 1.1 times larger than the Applied for (KW) value.

[52] Commission Opinion and Order, Case No. U-18091, July 31, 2017. Available at https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000001UTLi

Q. HOW DO THESE FIGURES COMPARE TO DTE'S NEAR-TERM PROJECTIONS?

A. They exceed even the most aggressive renewable scenario in the IRP. The High Renewable scenario projects 240 MW_{DC} of solar and 500 MW of wind to be installed by the start of 2021. There is more than two and half times as much solar in DTE's interconnection queue right now. Meanwhile, the 2017 Reference scenario, assuming only 72 MW_{DC} of solar and 311 MW of wind by the state of 2021, is even more out of touch with the current state of the market. The market is already demonstrating through the interconnection queue and an early response to the recent PURPA ruling that it will greatly exceed DTE's near-term build plans in its IRP. By ignoring distributed solar as a resource to help meet its power needs, DTE again shortchanges distributed resources in its IRP.

Q. DID DTE ASSUME ANY LIMITATIONS ON THE QUANTITY OF SOLAR THAT COULD BE DEPLOYED IN A GIVEN YEAR?

A. Yes. DTE has placed an arbitrary limit of 500 MW of solar and 1,000 MW of wind per year in its Strategist model. (MECNRDCSCDE-2.23, Ex. ELP-18 (KL-18)) While DTE admitted in this response that "there is no supporting documentation for this assumption," data from FERC Form 860 indicates that a number of states have exceeded the 500 MW limit in a given year. Illinois has announced that it will procure approximately 750 MW of new solar in the upcoming year and at least 1,500 of new solar by 2020.[53] California has installed more than 1,000 MW_{DC} in each of the past 5 years (in fact, it has averaged over 2,000 MW_{DC} per year). North Carolina installed 1,164 MW_{DC} in 2015 and 981

[53] https://www.quarles.com/publications/illinois-enacts-legislation-to-kick-start-additional-renewable-energy-development/

MW_{DC} in 2016, while Georgia and Utah installed 976 MW_{DC} and 864 MW_{DC}, respectively, in 2016.[54]

While there is not sufficient information in the record to determine whether this was a binding restriction in the modeling that DTE performed, assigning an arbitrary limit to the amount of solar that can be developed in a year is another instance where DTE treats renewable energy as an afterthought when considering how to best meet its customers' future needs.

Q. IS DTE OPEN TO UTILIZING THIRD-PARTY DEVELOPED PROJECTS FOR ITS RENEWABLE OBLIGATIONS?

A. Yes. DTE has indicated that it is willing to either develop its own projects or purchase projects from third-party developers, although it views this as part of the up to 300 MW of market purchases that it might make each year. (ELPCDE-9.2b, Ex. ELP-2 (KL-2)) Given that a number of projects are currently under development in Michigan based on the MISO interconnection queue, that the PURPA case order has spurred substantial activity in DTE's territory, and the number of other states that have rapidly added new renewable energy capacity, DTE could avail itself to market opportunities to add more wind and solar capacity sooner through PPAs or purchases than through internally developed projects.

Q. HOW DO DTE'S NEAR-TERM PROJECTIONS FOR SOLAR INSTALLATIONS COMPARE TO OTHER STATES?

A. Many states have seen much higher deployment rates that what DTE is proposing. Of course, solar development is dependent on the particular policy of a given state, but the trend across the country is clear. In both regulated and restructured markets, solar deployment is accelerating at a rapid pace.

[54] See Lucas Workpapers for data.

One way of evaluating the potential scale of solar development in coming years is to look to states that, like Michigan, have vertically integrated utilities. Several states with vertically integrated utilities have seen dramatic increases in utility-scale solar deployment. Nevada, North Carolina, and Utah saw large increases in PURPA projects. Georgia and Florida saw their utilities issue sizable RFPs for solar. South Carolina recently passed legislation that will open its solar market up to new development. Nevada has allowed large customers to choose their electricity supplier, many of whom demanded solar. Figure 13 shows the annual utility-scale installations in these states since 2012, along with 2017 estimates.

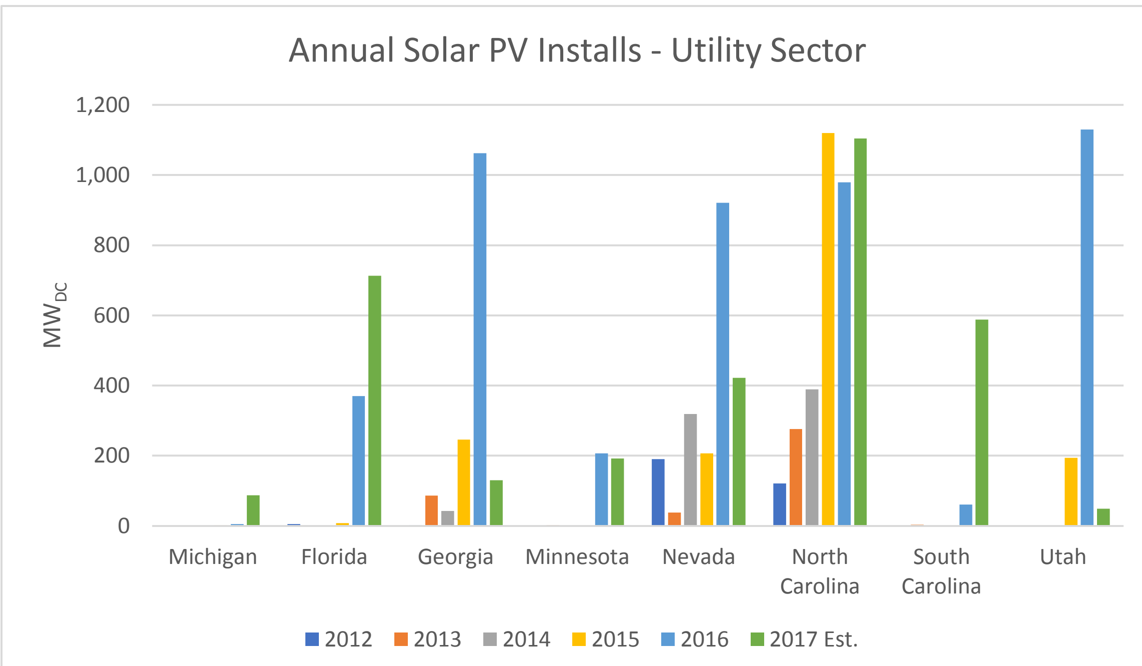

Figure 13 - Utility Scale Deployment for Select States

These vertically integrated states have seen solar development grow from (at times) zero MW per year to multiple hundreds of MW per year within a few years. When these changes occurred, they often happened very quickly. Michigan is poised to experience a similar disruptive change with the Commission's forthcoming PURPA ruling. In just the past four months, 222 MW_{AC} of solar has been added to Consumers

Energy's DG interconnection queue.[55] While DTE's PURPA ruling has not been finalized, the Commission has directed it to use a similar methodology as Consumers Energy, and even before the specific avoided costs were completed, 172 MW worth of 2 MW projects have applied to interconnect with DTE's system. Interest in Michigan's solar market will likely grow substantially in the coming years, with much of this driven from updated PURPA avoided costs.

DTE's South-Facing Fixed-Tilt Solar PV Design Assumptions are Inappropriate

Q. WHAT TECHNOLOGY AND OPERATING CHARACTERISTICS DOES DTE ASSUME FOR ITS SOLAR PROJECTS?

A. DTE assumes traditional south-facing fixed-tilt projects with a 20-year life and an annual degradation of 0.8%. (ELPCDE-7.3 Supplemental, Ex. ELP-19 (KL-19), WP KJC-100.) The annual degradation figure represents how much the panel output decreases each year. The IRP report uses a net AC capacity factor of 19-20%. (IRP Report at 125.) This represents the total amount of energy produced by 1 MW_{AC} of solar divided by 8,760 hours in a year.

Q. HOW DO THESE ASSUMPTIONS COMPARE TO TECHNOLOGY THAT IS BEING INSTALLED TODAY?

A. The 20-year life is shorter than would be expected from a newly installed project. While it is true that many commercial PPAs have a 20-year contract life, the actual useful life of the project typically exceeds this. Certain solar panels carry 25-year warranties, and PPAs have been signed for 25 years. Further, if DTE owns a system, it should base the operating life on the asset, not the typical length of a commercial contract.

[55] https://www.consumersenergy.com/~/media/CE/Documents/renewables/generator-interconnection/generator-interconnection-status-report.ashx?la=en

The annual panel degradation of 0.8% per year is also higher than is typically assumed. While DTE does use 0.5% in its LCOE calculator, which is consistent with the default value in the System Advisor Model from the National Renewable Energy Laboratory,[56] the 0.8% annual figure is used in the 2016 scenarios and sensitivities modeling. DTE updated this value to 0.5% for its 2017 modeling, but as the bulk of the IRP analysis was done with the 2016 values, the update does not make much difference. (ELPCDE-6.6c, Ex. ELP-20 (KL-20)) Panel degradation is a critical element of a PV system's performance. Since degradation compounds over time, DTE's assumption of 0.8% annual degradation results in projects losing 14.8% of its output in year 20 and 18.2% of its output in year 25. Under a 0.5% annual degradation, the reduction in output would be 9.5% and 11.8% after 20 and 25 years, respectively.

When these figures are compared to a leading panel manufacturer today, the overly conservative nature of DTE's assumptions are clear. SunPower offers commercial panels that have a performance guarantee for 25 years that includes removal of any defective panels along with shipping and installation of new panels. Further, it guarantees that the power decline after 25 years will only be 8%.[57] While this premium product is more expensive today, its degradation performance is substantially better with an equivalent annual degradation factor of 0.33%, nearly a third of DTE's assumption. The compounding impact of the various annual panel degradation values is seen in Figure 14 below.

[56] https://sam.nrel.gov/
[57] https://us.sunpower.com/commercial-solar/products/panel-warranty/

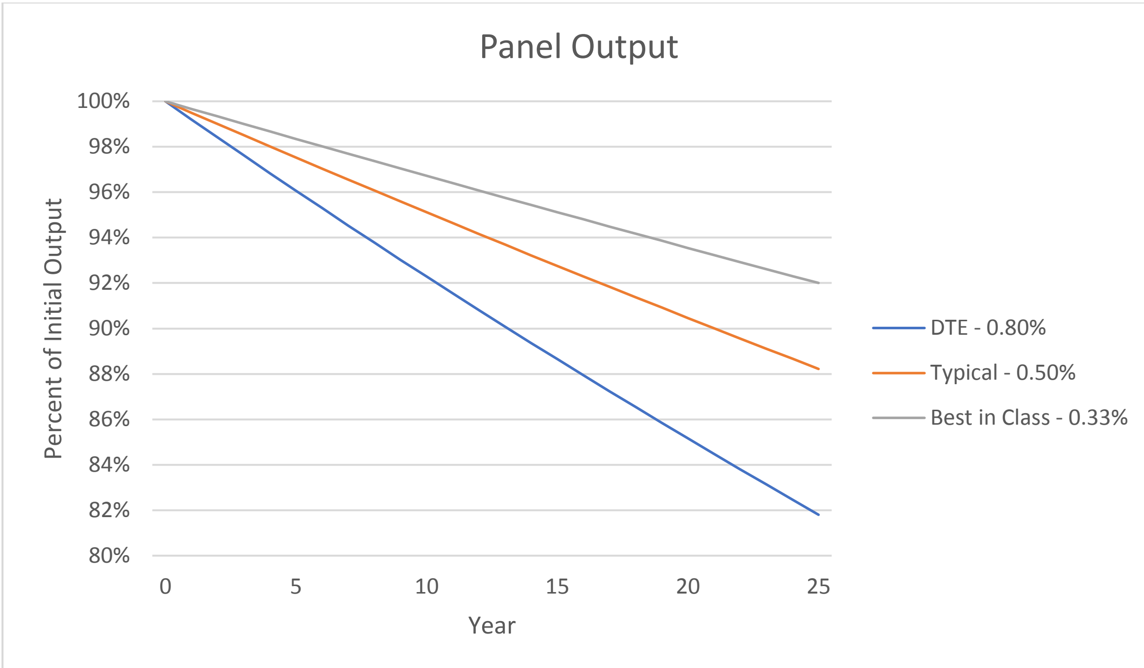

Figure 14 - Panel Output vs. Degradation

Improving lifetime performance and reducing panel degradation is a major focus of the industry today. As the industry shifts its focus to these key characteristics, it is likely that panels on future projects will retain even more of their original output than even today's best in class. Regardless, the use of a 20-year life and a 0.8% annual panel degradation substantially understates the contribution that solar can make to DTE and its customers both in terms of cost and capacity contribution. When combined with DTE's questionable O&M costs, one can see the combined impact of solar in Table 2 below.

O&M ($/kW-year)	Lifespan	Annual Degradation	LCOE ($/MWh)	Increase
$9.00	25	0.33%	$76.44	
$9.00	20	0.80%	$81.09	6.1%
$12.00	20	0.80%	$83.41	9.1%
$23.00	20	0.80%	$91.92	20.2%

Table 2 - Impact of O&M, Lifespan and Degradation Assumptions on LCOE

Q. ASIDE FROM THE OPERATIONAL CHARACTERISTICS, HAVE YOU FORMED AN OPINION ABOUT DTE'S CHOICE TO ASSUME ONLY SOUTH-FACING FIXED-TILT SYSTEMS?

A. South-facing systems are designed to maximize the total amount of energy that a solar system produces. While energy production is the most important attribute for some systems – particularly those that participate in retail markets – DTE's IRP was intended to address both energy and capacity needs. DTE's failure to optimize its assumptions on the technology and orientation of the PV systems is inexcusable but unfortunately consistent with the other ways in which it undercuts solar in its IRP.

Q. HOW DOES THE CHOICE OF TECHNOLOGY AND ORIENTATION AFFECT THE AMOUNT OF CAPACITY FROM SOLAR?

A. While MISO's peak hours vary by year, they historically have fallen between 2 and 5 EST during summer weekdays, after the sun has passed its southern-most position in the sky. These peak hours are the same hours that MISO uses to calculates DTE's peak demand and determine DTE's capacity obligation. Orienting fixed-tilt systems due south is not the best choice to maximize the capacity value that solar PV can provide, and by assuming south-facing, fixed-tilt systems in its IRP, DTE is understating the capacity contribution that solar can make towards meeting its capacity needs.

Q. WHAT ARE THE BENEFITS OF TRACKING SYSTEMS FOR BOTH ENERGY AND CAPACITY?

A. As discussed earlier in my testimony, there has been a dramatic shift from fixed-tilt to single-axis tracking systems. As the incremental costs of trackers has fallen, the energy production and capacity benefits of single-axis tracking systems have exceeded the incremental costs, and the market is responding by aggressively adopting this technology. By increasing the total quantity of energy produced throughout the year, and by increasing production during critical mid- to late-afternoon hours that are used to measure a projects' MISO capacity contribution, single-axis tracking systems provide more value to its owner than a fixed-tilt system. This is particularly relevant for DTE given that its needs are largely driven to replace retiring resource capacity.

Q. DO YOU HAVE ANY DATA RELATED TO THE DEPLOYMENT OF SINGLE-AXIS TRACKING SYSTEMS IN RECENT YEARS?

A. Yes. Starting in 2016, the Federal Energy Regulatory Commission (FERC) began to collect data on single-axis and dual-axis tracking systems in its Form 860. As seen in Figure 15 below, single-axis trackers have become a much larger share of the technology used in the past few years. For systems listed in FERC Form 860 (which are primarily utility-scale projects) that became operational in 2016, 72% of the installed nameplate capacity utilized single-axis trackers. This was an increase from the 55% and 41% of MW that used single-axis trackers in 2015 and 2013, respectively. Given how the balance has shifted between the incremental price of the tracking system and the incremental value of energy and capacity output from tracking systems, this trend is likely to continue.

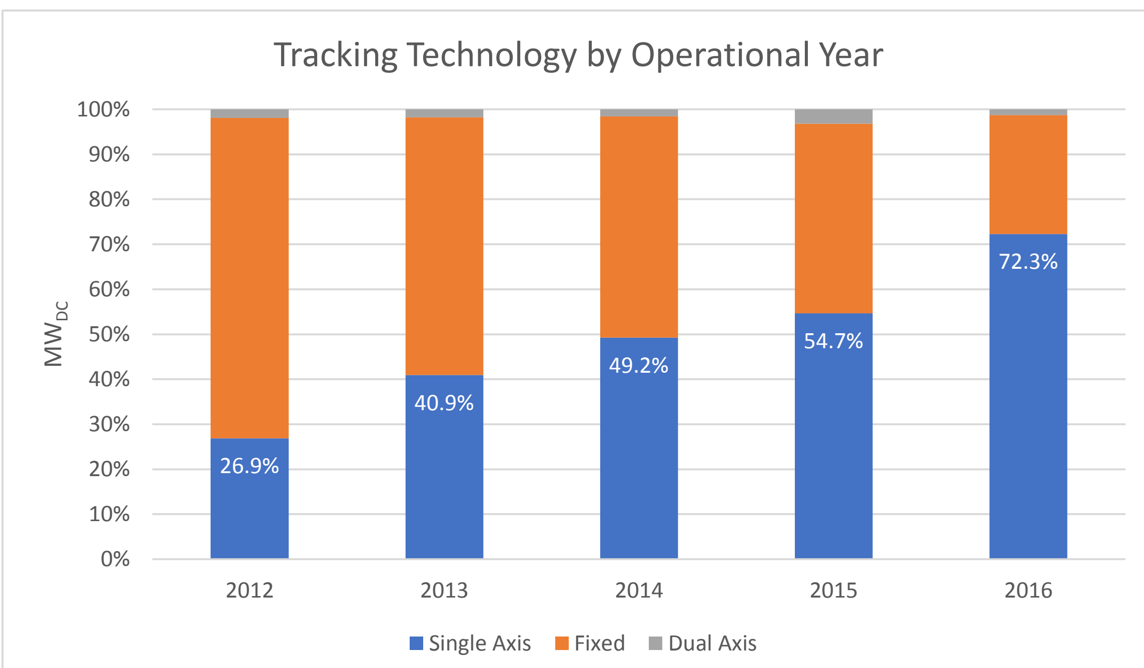

Figure 15 - Tracker Penetration by Operational Year

Q. HAVE YOU MODELED THE IMPACT OF DIFFERENT SYSTEM CONFIGURATIONS USING MICHIGAN-SPECIFIC DATA?

A. Yes I have. Using the System Advisor Model from the National Renewable Energy Laboratory, I modeled five different generic PV systems using meteorological data from Flint, Michigan. Three were fixed-tilt (facing south, southwest, and west) and two were tracking systems (both single-axis and dual-axis). The fixed-tilt systems had a DC/AC ratio of 1.2, consistent with DTE's assumption. The tracking systems were assigned a DC/AC ratio of 1.3 based on the actual ratios for installed single-axis tracking systems between 2014 and 2016 listed in FERC Form 860. I compared the overall generation between the systems to calculate an expected capacity factor and calculated the expected capacity credit using the MISO Business Practice Manual method. Because there have been discussions in MISO's LOLE Working Group about implementing a more sophisticated methodology for solar projects,[58] I also modeled the results using the more complex MISO ELCC Method used for wind projects.[59]

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS?

A. The tracking systems are clearly superior to fixed-tilt, south-facing systems in terms of both overall energy production and expected capacity contribution.

Under the BPM methodology, single-axis tracking systems provided 17.6% more energy and 28.9% more capacity than fixed-tilt, south-facing systems. Dual-axis trackers did even better, increasing energy output by 27.7% and capacity by 34.1%. Part of this

[58] The LOLE Working Group looks at the "loss of load expectations" which is used to inform the magnitude of capacity reserves that MISO utilities are required to maintain. More details available at https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20150806/20150806%20SAWG%20Item%2007%20Solar%20Capacity%20Credit.pdf

[59] The BPM method takes the average performance in hours ending 15 to 17 EST from June to August. The ELCC method is more complex, and is based on performance in the eight peak hours in the past ten years. The actual historic peak hours were taken from MISO's Capacity Credit Calculation report. These dates were analyzed to determine the most likely date and time range when the MISO system would peak. Please see Lucas workpapers for the complete analysis.

increase is due to the higher DC/AC ratio of tracking systems, which optimizes the amount of power that the trackers could gather.

Among fixed-tilt systems, south-facing was the worst choice for DTE's capacity needs. While this orientation did produce more energy than southwest or west-facing fixed-tilt systems, it contributed much less capacity. Under the BPM method, west-facing systems produced 17.5% less energy but 17.5% more capacity than south-facing systems. Southwest-facing systems had the best combination for fixed-tilt systems, only giving up 5.1% of energy while increasing capacity by 18.7%. The results for the BPM methodology are shown in Figure 16 below.

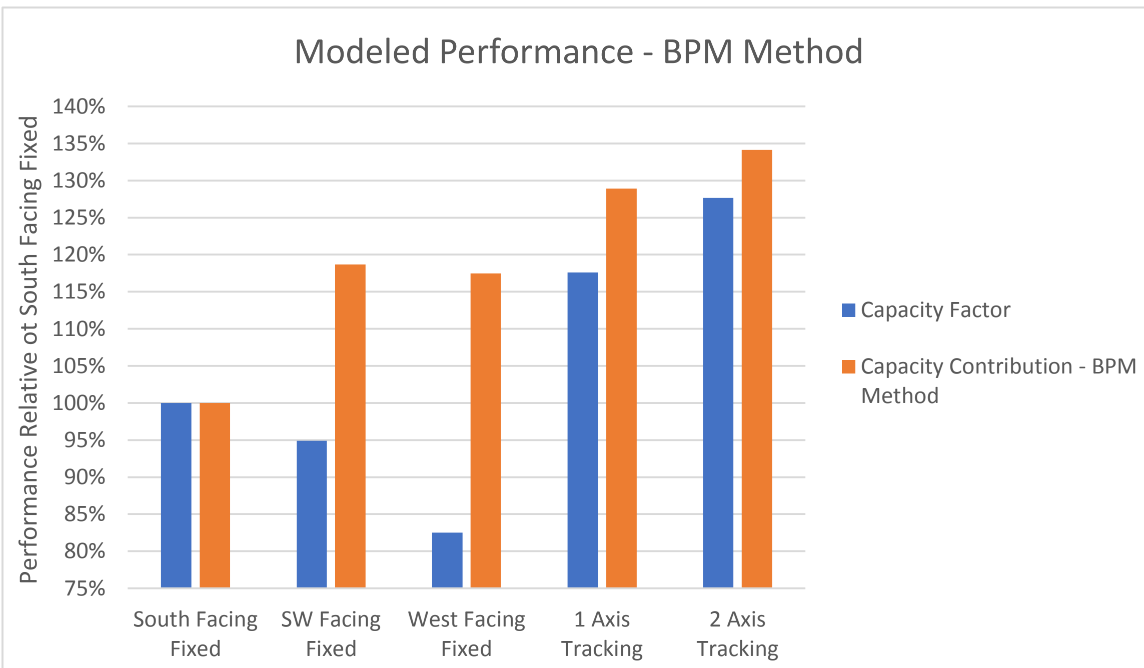

Figure 16 - BPM Modeled Performance

Under the more sophisticated ELCC methodology, solar produced even better capacity results than under the BPM methodology. Single-axis tracking systems provided between 31.0% and 32.1% more capacity than fixed-tilt, south-facing systems. Dual-axis tracking systems increased capacity contribution by between 36.1% and 37.1%. West-facing systems gained between 18.7% and 19.2% in capacity, and southwest-facing systems gained between 20.2% and 20.8% of capacity over the south-facing systems. The ELCC methodology results are summarized in Figure 17 below. Note the capacity factor is identical in both charts.

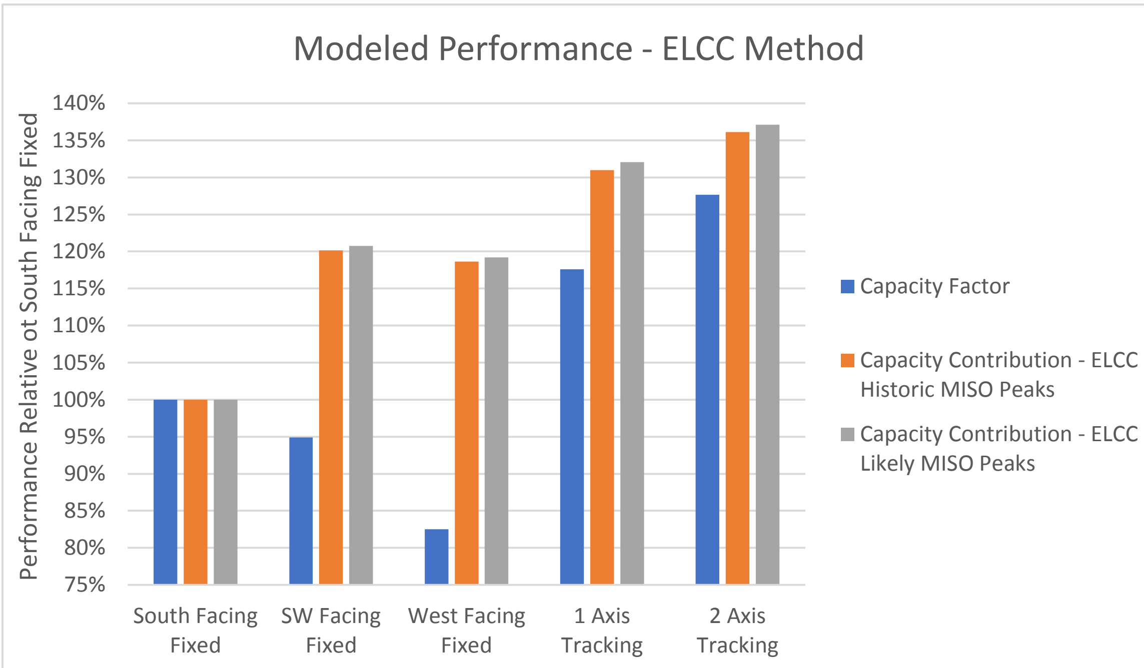

Figure 17 - ELCC Modeled Performance

When these figures are compared to the standard assumptions that DTE uses, it is clear that DTE is leaving capacity and energy on the table by choosing to model only south-facing, fixed-tilt systems. Table 3 below translates the improvements relative to DTE's standard assumptions.

Adjusted to 19% CF and 50% Capacity Contribution	South Facing Fixed	SW Facing Fixed	West Facing Fixed	Single Axis Tracking	Dual Axis Tracking
Capacity Factor	19.0%	18.0%	15.7%	22.3%	24.3%
CC – BPM Method	50.0%	59.3%	58.7%	64.4%	67.1%
CC – ELCC Historic MISO Peaks	50.0%	60.1%	59.3%	65.5%	68.1%
CC –ELCC Likely MISO Peaks	50.0%	60.4%	59.6%	66.0%	68.6%

Table 3 - Summary of Modeled CF and CC

Q. HOW DID THESE ASSUMPTIONS AFFECT DTE'S IRP?

A. DTE's renewable energy assumptions were not driven by an effort to meet its capacity needs with a portfolio of distributed generation assets, but rather to meet its statutory obligations. I have discussed this problem earlier in my testimony.

Q. EVEN IF IT MIGHT NOT HAVE FIXED DTE'S CORE ISSUE RELATED TO DISTRIBUTED RESOURCES, WHAT DOES THE RESULT OF YOUR ANALYSIS SHOW?

A. In the scenarios in which DTE did model more solar than was necessary for compliance for its RPS obligation, the lack of optimizing the system type and orientation resulted in higher costs than would have otherwise been computed. Once the portfolios were designed, the lower performance of the south-facing fixed-tilt systems causes these scenarios to look worse than they would have been under better assumptions, further obscuring the potential contribution of solar to meet the needs of DTE and its customers.

Given its need for capacity more so than energy, DTE should be seeking to optimize the capacity credit that a solar PV system could provide to its system. While the dual-axis tracker is the best overall performer for this geography, the single-axis tracker has been deployed more and will likely have lower O&M costs when compared to a dual-axis system.[60] Even if DTE does not want to deploy tracking technology on all of its PV systems, it has not carefully considered the orientation of fixed-tilt systems to ensure that the optimum combination of capacity and energy can be provided to its grid. By choosing to model only fixed-tilt, south-facing solar systems, DTE ignores significant energy and capacity benefits that single-axis tracking systems could provide.

[60] Is it interesting to note that the vast majority (85%) of dual-axis tracking systems in FERC form 860 that were deployed since 2012 were deployed in Texas. This state is unique in that it has an energy-only wholesale market, so the value of extracting as much energy as possible can outweigh the incremental cost of dual-tracking systems over single-tracking systems.

Q. DO YOU HAVE INFORMATION REGARDING AN ACTUAL SINGLE-AXIS TRACKING SYSTEM LOCATED IN THE MIDWEST?

A. Yes. The Aurora project, originally developed by Geronimo Energy, is a 130 MW_{DC}/100 MW_{AC} single-axis tracking solar facility comprised of many individual 2 to 10 MW projects located in Minnesota. It was selected by the Minnesota Public Utilities Commission as part of a 2012 solicitation to provide Xcel additional capacity.[61] The Aurora project demonstrated that even in 2012, the economics of solar was sufficiently robust to compete against natural gas plants.

For the Aurora Project, the Administrative Law Judge who heard the case found that the Aurora project would receive a capacity credit of 71.2% due to its tracking hardware.[62] While this project is further west than DTE's territory and thus benefits from additional solar insolation during MISO's peak hours, this effect is unlikely to be the primary source of the increase. Whether a similar project in Michigan would receive a capacity credit of 71.2% or 65% as modeled above, either of these figures is substantially higher than the 50% credit that DTE assumes in its IRP.

Q. DID DTE CONSIDER TRACKING SYSTEMS?

A. No. DTE did not consider tracking systems at any point in the IRP analysis period. When asked about this in a data request, DTE pointed back to the direct testimony of Company Witness Terri Schroeder. (ELPCDE-5.42, Ex. ELP-21 (KL-21)) Ms. Schroeder's direct testimony referenced in the data request is vague, stating:

> To date, the Company has primarily installed fixed tilt ground mounted solar installations. As solar equipment technology continues to evolve DTE Electric will evaluate project economics, including tracking systems, with each future request for proposal. (Schroeder Direct at 12.)

[61] *In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process, Docket No. E-002/CN-12-1240*, Minnesota Public Service Commission.
[62] *Docket No. E-002/CN-12-1240, Findings of Fact, Conclusions of Law, and Recommendation*, Minnesota Public Service Commission. Available at https://mn.gov/oah/assets/2500-30760-NSP-competitive-resource-report_tcm19-164285.pdf.

Apparently, DTE has failed to notice that the market has already evolved. As seen in Table 15 above, the market completely switched in 4 years, moving from roughly 25% tracker / 75% fixed-tilt to roughly 75% tracker / 25% fixed-tilt. DTE does not need to continue to evaluate where the market is, it needs to simply observe where it is today.

Given their clear benefits over fixed-tilt systems, and the speed with which the market is deploying single-axis tracking systems, it is unreasonably that DTE did not include single-axis tracking systems in its analysis. This is one more example of where DTE's choices and assumptions put solar at an unfair and unjustified disadvantage to other technologies.

DTE's Solar and Wind Deployment Schedule Fails to Optimize Tax Credits

Q. ARE THERE BENEFITS OF ACCELERATING THE DEPLOYMENT OF SOLAR AND WIND RESOURCES IN THE NEXT FIVE YEARS?

A. Yes. There are substantial benefits of acting quickly to deploy more wind and solar resources. Under current federal law, the production tax credit (PTC) and investment tax credit (ITC) that benefit wind and solar, respectively, are set to phase out in the coming years. The PTC stepdown has already started. For projects commencing construction in 2017, the credit was reduced by 20% from its 2016 value of $23/MWh. For projects starting in 2018 and 2019, the credit will be reduced by an additional 20% each year. Projects that commence construction in 2020 or beyond will not receive a PTC.[63]

The solar ITC follows a different schedule. The current 30% ITC will be in place for projects that commence construction through the end of 2019. At that point, the credit will drop in successive years to 26% and 22%, before stabilizing at 10% for projects in 2022 and beyond.[64]

[63] https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc
[64] https://energy.gov/savings/business-energy-investment-tax-credit-itc

While DTE's High Renewable buildout schedule might be able to safe-harbor some of the wind and solar projects, most of the solar build occurs in 2022 and beyond. Likewise, for the 75% Reduction in CO2 sensitivity, the vast majority of renewable energy will be installed after the tax credits have expired or fallen to their terminal value.

Other utilities have seen the value in stepping up investment prior to the expiration of the tax credits. For example, MidAmerican Energy Company announced last year that it would invest $3.6 billion to construct 2,000 MW of wind to be online by 2019 as part of its goal to move to 100% renewable energy.[65] Xcel Energy has issued a competitive request for proposals to build up to 1,000 MW of wind and up to 700 MW of solar in Colorado as part of its 2016 IRP.[66] On January 8, 2018, Xcel released the results of the bidding from this IRP, and the results were quite staggering. Standalone wind projects bid a median price of $18.10/MWh, while standalone solar projects had a median bid of $29.50/MWh. Solar plus storage bids were also heavily bid, with only a small premium and median bids of $36.00/MWh.[67]

Given DTE's focus to reduce the cost of its Proposed Plan, which is after all paid for by DTE's customers, it is inappropriate to bypass the savings that would accrue to customers by delaying its renewable builds beyond the closing tax credit window. It should follow the lead of other Midwest utilities and make a stronger push for near-term wind and solar development.

Q. DID DTE EXPLAIN WHY IT HAS NOT PROPOSED MORE RENEWABLES IN THE NEXT FIVE YEARS?

A. Not directly, although this failure is consistent with DTE's general view on distributed resources. It appears that the only renewable energy deployment forecasts that DTE used

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65 https://www.midamericanenergy.com/news-article.aspx?story=797
66 https://www.utilitydive.com/news/xcel-energy-proposes-shuttering-2-colorado-coal-plants/503878/
67 https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/

were those listed above in my testimony. The most aggressive of these scenarios only assumes 300 MW by 2022, and the reference scenarios lower yet. However, DTE is foregoing a substantial benefit by delaying the construction of more renewables.

Additionally, DTE appears to have configured the model to solve for capacity needs as the primary consideration, and any optimization is built around minimizing the cost of acquiring this capacity. DTE does not appear to have considered a situation when the energy output of a renewable energy facility is cheaper than the variable energy costs of a fossil generator. For instance, if in the future the cost of producing energy from wind is less than the variable costs of producing energy from a NGCC, the model will not build the wind resource. DTE considers that any builds of renewables that displace higher variable energy costs from one resource by building another with lower variable energy costs would be "added superfluously." (ELPCDE-7.2c, Ex. ELP-22 (KL-22))

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH DTE'S RENEWABLE ENERGY ASSUMPTIONS IN ITS IRP.

A. DTE's renewable builds in its Reference scenarios is limited to meeting its statutory obligations under the RPS. It placed limits on the quantity of renewable projects that could be developed in a given year. Its choice of price projections for solar in particularly are high. It ignores the dominant market trend towards and demonstrated performance benefits of single-axis tracking systems. It has not thought strategically about how to best leverage the expiring federal tax credits through accelerated renewable builds. And despite having a long-term corporate goal to reduce GHG emissions, DTE has done little in its IRP to demonstrate near-term activities to attain those laudable goals.

IRP Energy Efficiency Assumptions

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. In this subsection, I discuss two studies that were performed for DTE to analyze the potential for energy efficiency and demand response, and question program design assumptions that may have limited the perceived availability of these resources. I then discuss DTE's failure to properly incorporate the study results into its base load forecast. Finally, I close the section by showing that DTE's own analysis shows it did not select the most reasonable energy efficiency plan among the alternatives that it examined.

DTE's Energy Efficiency and Demand Response Potential Studies

Q. PLEASE DESCRIBE THE ENERGY EFFICIENCY AND DEMAND RESPONSE POTENTIAL STUDIES THAT INFORMED DTE'S IRP

A. DTE commissioned two studies to investigate the potential to reduce energy usage and peak demand in its service territory, both performed by GDS Associates. The energy efficiency potential study (EE Study) is found in Exhibit A-32, and the demand response (DR Study) is found in ELPCDE 1.18, Ex. ELP-23 (KL-23). Both studies are dated April 20, 2016.

The potential studies follow a similar structure. The first step determines a technical potential based on a specified suite of programs (such as residential appliance rebates) that are comprised of dozens of individual measures (such as air conditioners). This represents the highest reduction that could be possible given technology constraints. For instance, it might assume that all new air conditioners that are installed are the highest efficiency on the market. The second step calculates an economic potential. The technical potential is trimmed by applying cost-effectiveness screens. In this filter, if the most efficient air conditioner is not economic to install (meaning the expected savings from the reduced usage are less than the incremental cost of the more efficient unit), then the economic potential will drop this measure. The final step is calculating an achievable potential. This step layers on "real-world" factors such as program participation rates and budget constraints. The achievable potential represents what one can reasonably expect out of the program based on all the assumptions embedded in the report.

Q. WHAT ARE SOME OF THE ASSUMPTIONS AND CONSTRAINTS USED IN THE POTENTIAL STUDIES?

A. One of the primary assumptions in the EE Study was that incentives are capped at 50% of the incremental measure cost. (EE Study at 8.) Another is that demand response programs take 20 years to ramp up to their full participation rates. (DR Study at 19.)

Additionally, cost-effectiveness was calculated using the Utility Cost Test (UCT). This test includes all utility costs (e.g. program administration and rebates) and benefits (e.g. avoided energy and capacity), but does not include participant or societal costs and benefits (e.g. the non-rebated cost of the measure or health impacts from reduced criteria pollutants). Further, while some measures produce natural gas savings, GDS did not include these benefits in its calculations. (EE Study at 37.) Instead, it takes stock of the programs strictly from the utility perspective.

Q, WAS DTE ASKED ABOUT THE CHOICE TO LIMIT INCENTIVESE TO 50% OF THE INCREMENTAL COSTS?

A. Yes. With regard to the 50% limit, DTE stated that this level "is identical to the assumption used in the 2013 Michigan Statewide Energy Efficiency Potential Study published by the Michigan Public Service Commission" and that it is "a reasonable target based on the current financial incentive levels used by the Company for program participants in existing energy efficiency programs." (ELPCDE-11.13, Ex. ELP-24 (KL-24))

Q. WHAT IS YOUR RESPONSE TO THIS ANSWER?

A. Both DTE's 2016 EE Study and the 2013 Commission study were performed by GDS. Both contain practically verbatim language on the justification for the 50% limit, with the exception being that the state-wide report references Consumers Energy and three scenarios rather than two. As such, the response that the values are identical is neither surprising nor meaningful – the same consultant performed both studies with recycled justifications for this figure.

Comparing the incentive level to those in existing energy efficiency programs is a red herring. The goal of exploring additional energy efficiency in this case is not to sustain past performance, but to seek if energy efficiency can contribute to an alternative solution for an identified power need. DTE should not be limiting its scope of analysis in any way based on its historic performance but instead seeking to maximize future cost-effective performance.

Q. WAS DTE ASKED ABOUT THE 20-YEAR DEMAND RESPONSE RAMP-UP RATE?

A. Yes. DTE answered "[p]er GDS Associates, while other utilities may have a fast ramp up speed due to a variety of reasons, the potential study chose a more conservative, 20-year approach. Additionally, DTE already has several DR programs in existence. Fast ramp up speeds usually come with brand new programs, where easy-to-get customers are readily willing to opt in to the program." (ELPCDE-11.9, Ex. ELP-25 (KL-25))

Q. WHAT IS YOUR RESPONSE TO THIS ANSWER?

A. I agree with GDS that the DR Study chose a more conservative approach. But as with the EE Study assumptions, this is not the time for conservative thinking. As discussed later in my testimony, demand response programs can contribute to DTE's capacity needs and do so with substantially less cost than can the Proposed Project. DTE should be looking to maximize the near-term deployment of demand response to help meet its power needs, not taking a "conservative" approach.

Regarding GDS's comment that DTE has several demand response programs already, it is also true that GDS has identified many demand response programs that it is not implementing. The DR Study lists sizable demand reduction potentials associated with rate designs such as time-of-use, real-time pricing, and dynamic peak pricing. It also identifies special rates for specific purposes, such as golf cart charging and thermal electric storage for cooling.

Further, DTE identified several programs, such as volt-var optimization and conservation voltage reduction, bring-your-own-device programs, and programmable thermostat programs that it considered on either limited base or suggested that it did not have sufficient information to include in the Proposed Plan. Even though DTE does have some existing demand response programs, there are no shortage of new opportunities available to it.

Q. PUTTING ASIDE THESE CONCERNS, WHAT WERE THE RESULTS OF THE EE STUDY AND DR STUDY?

A. The overarching takeaway from the report is that there is a massive quantity of cost-effective energy efficiency and demand response available in DTE's territory. GDS summarizes the technical, economic, and achievable potential for 2025 and 2035. Figures 18 and 19 show these results for energy efficiency programs in 2025 and 2035, respectively.

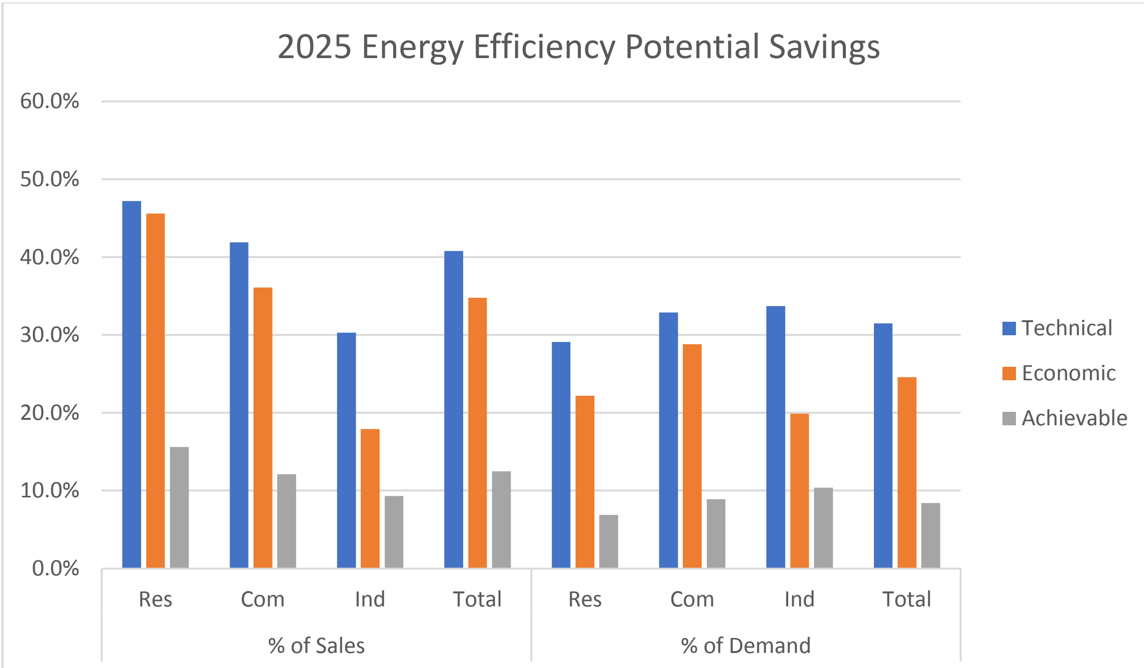


Figure 18 - 2025 Energy Efficiency Potential Savings

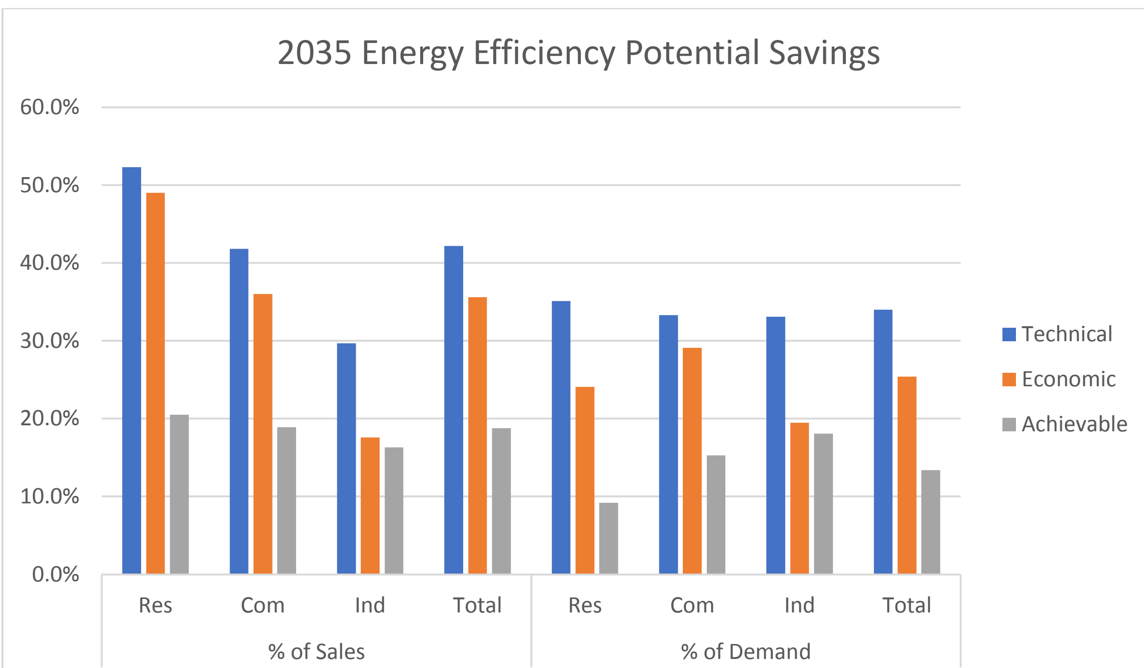


Figure 19 - 2035 Energy Efficiency Potential Savings

From energy efficiency programs alone, DTE has the economic potential to reduce its sales and demand by 34.8% and 24.6%, respectively, in 2025 compared to the forecasted use for that year. This represents an economic potential of 3.5% per year for energy efficiency. However, due to the assumptions embedded in the EE Study, GDS reports achievable potentials of 12.5% and 8.4% for sales and demand reductions, respectively, in 2025. These figures do increase to 18.8% and 13.4% for sales and demand reduction, respectively, in 2035 as programs slowly ramp up, but even then barely half of the economic potential is captured even after 20 years.

The DR Study shows similar economic potential. GDS analyzed two technology scenarios – a base case and a "smart thermostat" case. The smart thermostat case deployed additional technology that enabled new programs such as air conditioning control by thermostat instead of switch. The demand reduction economic potential was 31.6% and 40.6% for the base and smart thermostat case, respectively, in 2025. This remained largely unchanged in 2035, with economic potential of 31.5% and 38.6% for the base and smart thermostat case, respectively. These results are shown in Figures 20 and 21 below.

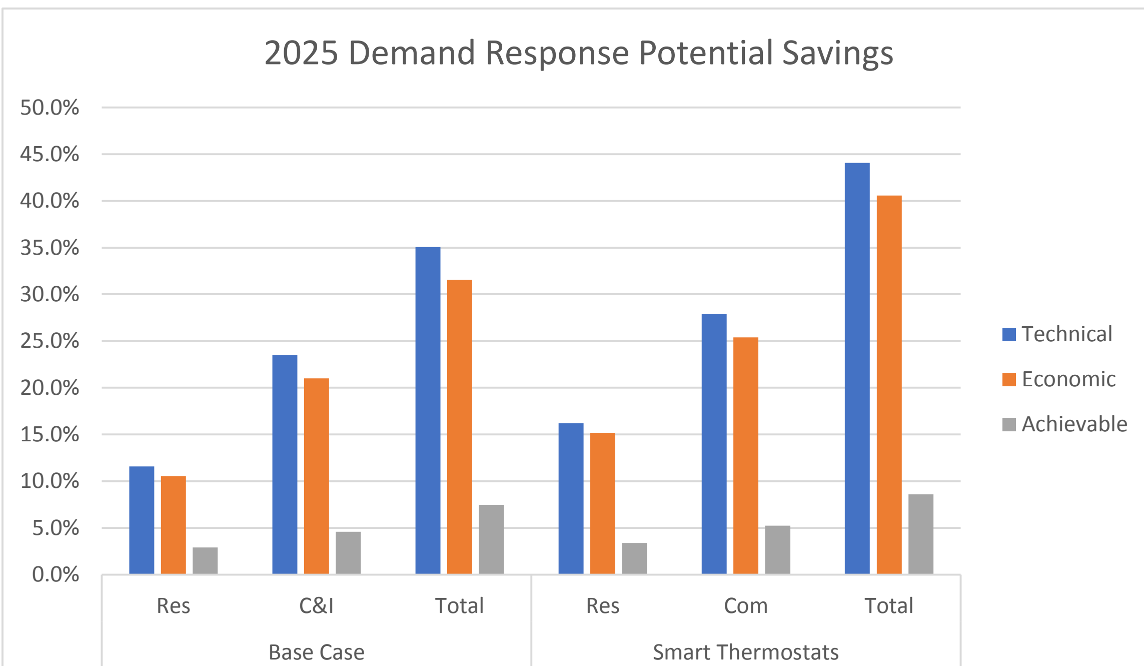


Figure 20 - 2025 Demand Response Potential Savings

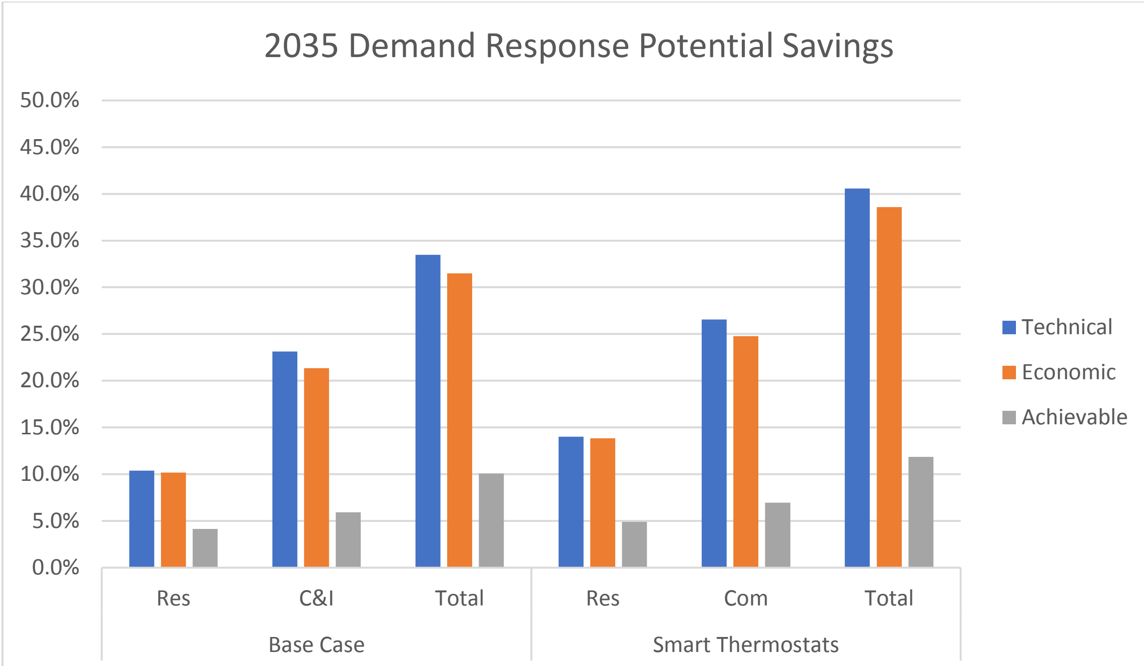


Figure 21 - 2035 Demand Response Potential Savings

As with the EE Study, there is a substantial drop off between the economic potential and the achievable potential. DTE projects a demand reduction of only 7.4% and 10.1% in 2025 and 2035, respectively, in the base case, and only 8.6% and 11.8% in 2025 and 2035, respectively, in the smart thermostat case. Even after 20 years, GDS predicts that barely a quarter of the economic potential can be realized.

Q. TO WHAT DO YOU ATTRIBUTE THE DROP OFF BETWEEN THE ECONOMIC AND ACHIEVABLE POTENTIAL?

A. While it is not possible to capture 100% of the economic potential, the drop off that GDS projects is sizable. This result is produced in part by the assumptions embedded in the potential study methodology. For the EE Study, DTE limited rebates to 50% of the incremental cost, even if increasing this amount resulted in additional cost-effective savings. It also did not consider any programmatic changes, such as increased marketing spend, that could increase participation and thus impact the achievable savings. Rather, it stated that "program improvement discussions were outside the scope of the potential study." (ELPCDE-11.12, Ex. ELP-26 (KL-26)) Both of these assumptions would tend to push achievable potential lower relative to the very high economic potential.

For the DR Study, GDS assumes a very slow ramp up and low penetration of key programs. For instance, GDS assumes that residential participation in a dynamic peak pricing program will be only 30% after 20 years. Likewise, it assumes that only 21% of residential customers will take advantage of a programmable thermostat program that controls air conditioners after 20 years.

These figures contradict other publicly available data on demand response programs. For instance, Baltimore Gas and Electric (BGE) launched several residential demand response programs as part of Maryland's EmPOWER program. In just four years, BGE's Smart Energy Rewards peak time rebate program attained an average participation of 71% of residential customers, while its PeakRewards direct load control by programmable thermostat attained penetration of 33% of homes in eight years.[68] These programs both attained substantially higher participation in a much shorter timeframe than DTE assumes.

Q. DID DTE INDICATE THAT THE EE STUDY CONTAINS AN ERROR THAT LED TO IT OVERSTATING THE TECHNICAL AND ECONOMIC POTENTIAL?

A. Yes. DTE indicated in a data request response that the EE Study contained a "formula error" that affected the technical and economic potential of the residential home energy reports and commercial lighting controls programs. (ELPCDE-11.12, Ex. ELP-26 (KL-26)) It does not appear to have issued an erratum to the EE Study, not did DTE's response contain sufficient information for me to incorporate these errors into my

[68] BGE's *Semi-Annual Report for Third and Fourth Quarters – July 1 through December 31, 2016* at 43. Available at ihttp://webapp.psc.state.md.us/newIntranet/casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9100-9199\9154\\792.pdf

analysis. However, no such error was noted in the DR Study, which contains a similar drop-off between the technical and economic potentials and the achievable potential.

Q. ARE THE DEMAND REDUCTIONS IN THE EE STUDY AND DR STUDY DUPLICATIVE OF EACH OTHER?

A. No, although there may be some modest overlap. The demand reductions in the EE Study come from using less energy from measures such as insulation (which reduce the need to run the air conditioner) as well as from measures such as appliance rebates (which helps install more efficient air conditioners that use less energy when running). Demand response programs do not duplicate these savings. Rather, they provide additional demand reductions from not running the air conditioning unit or running it less often.

That said, it is possible that there is some overlap between the demand reduction figures in each report. For instance, depending on what appliance stock GDS assumed in the DR Study, the benefit of turning off an air conditioner at peak times would vary. If it assumed a low level of energy efficiency, there would be a larger benefit of cycling off a unit that uses relatively more power than if it assumed broad penetration of high-efficiency units that use relatively less power. However, there will always be savings to be had from turning off even efficient appliances, so a large fraction of the demand response savings will remain additive to the energy efficiency reductions.

Q. WHAT ARE YOUR OVERALL IMPRESSIONS OF THE POTENTIAL STUDIES?

A. I am familiar with GDS's potential study methodology, having worked with them previously in the State of Maryland. Its potential study methodology is reasonable, but the results are, of course, a product of the assumptions embedded in the analysis. Between the artificial limitation on the incentive level and the slow adoption of programs, I believe that the potential studies understate the achievable potential that could be obtained with more aggressive program design and implementation.

Q. DOES DTE ASSUME THAT ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS WILL BE IMPLEMENTED THROUGHOUT THE IRP ANALYSIS PERIOD?

A. No. DTE assumes that no energy efficiency is implemented after 2030 (ELPCDE-4.11a, Ex. ELP-27 (KL-27)), and does not increase the levels of demand response past 2021 (WP KJC-2 and KJC-323). When asked about the cessation of energy efficiency programs despite the EE Study showing that incremental savings were available after 2030, DTE replied that since "the potential was used up," it was important to "value the effects that occur after the initial outlay of spending." (ELPCDE-4.10c, Ex. ELP-28 (KL-28))

Q. WHAT IS YOUR RESPONSE TO THIS ASSERTION?

A. It does not make any sense to me. Energy efficiency potential is not "used up." As demonstrated in the EE Study, there exists substantially more savings that will pass economic cost-benefit screens and could likely be realized if DTE were to modify its program design criteria. Further, the EE Study shows substantial potential beyond 2030. To suggest that DTE can "use up" all available energy efficiency as soon as 2023 requires it to also assume that there exist no program modifications that can capture additional savings. And as indicated in its data request responses, DTE appears to believe this fallacy. (ELPCDE-4.17d, Ex. ELP-29 (KL-29))

Further, the assumption that DTE will stop all energy efficiency programs after 2030 necessarily assumes that all cost-effective energy efficient savings are exhausted. After all, if cost-effective savings continue to be available, there is no justification for stopping these programs. Given the long and successful history of energy efficiency in this country, it is highly unlikely that DTE will run out of cost-effective energy efficiency programs in 13 years.

DTE Fails to Properly Account for Energy Efficiency and Demand Response Potential in its Base Load Forecast

Q. PLEASE DESCRIBE DTE'S BASE LOAD FORECAST.

A. Generally, DTE projects sales and peak demand to be relatively flat in the near term and to fall slowly over the long term. However, as with the renewable energy assumptions, there appears to be inconsistency between the sales forecasts that DTE used in different parts of its IRP. Figure 22 below shows the bundled sales forecast for both the 2016 and 2017 Reference case. The higher pair of forecasts are outputs of modeling runs found in DTE's workpapers and data request responses. The lower pair of forecasts are from Exhibit A-17. One can see that not only does the scale differ between the forecasts, but the year-to-year variation changes as well. Importantly, the 2016 values were the primary ones used in the IRP, and that pair exhibits the largest absolute and year-to-year difference.

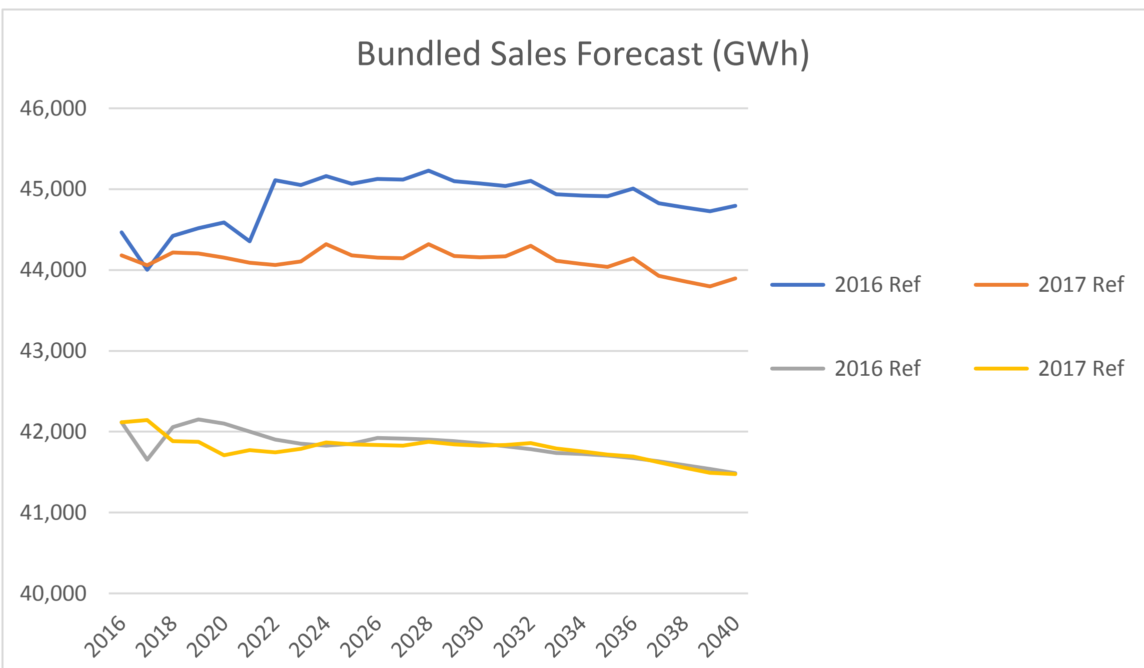


Figure 22 - Bundled Sales Forecast

Figure 23 shows the forecast for DTE's revenue adequacy requirement. In the near-term, the difference between the two forecasts is driven by the underlying forecast for bundled non-coincident peak demand. In the long term, the spread between the two versions is due to DTE's updated assumptions about MISO's UCAP requirement. In its 2016 forecast, DTE assumed a 7.2% long-term UCAP percentage requirement, which it increased to 7.8% in the 2017 forecast update based on MISO's updated LOLE Study Report. (ELPCDE-4.1, Ex. ELP-30 (KL-30))

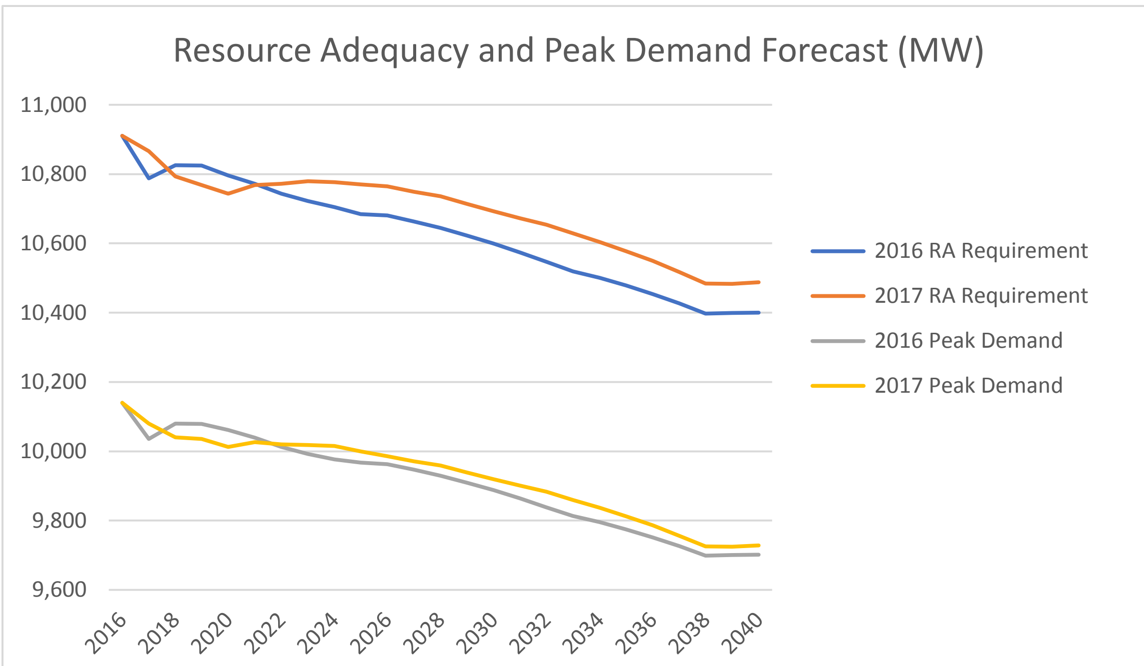


Figure 23 - Resource Adequacy and Peak Demand Forecast

The spread between the 2016 and 2017 peak demand forecasts is roughly 33 MW from 2025 and 2040. By increasing the percentage, the spread between the resource adequacy requirement increases to roughly 94 MW over this same time frame. Because MISO increases the reserve requirement percentage, DTE must hold a higher reserve of capacity resources over its projected peak load. At the same time, however, this increases the value of load reduction through demand response or energy efficiency –

every MW of load reduction now gets a "bonus" of 0.6% when the resource adequacy reserve is calculated in addition to the benefits from avoiding line losses.

Q. HOW DOES DTE INCORPORATE THE RESULTS OF THE DR STUDY INTO ITS IRP PROCESS?

A. It does not appear to be utilized at all. The DR Study shows 1,093 MW and 1,489 MW of achievable potential in 2025 and 2035, respectively, even with the unrealistically low ramp up rates discussed previously. However, DTE's actual demand response inputs neither match these values nor increase over time. Figure 24 below shows the DR Study achievable reduction results from 2020 to 2035 along with DTE's demand response assumptions in its 2016 and 2017 Reference case. While DTE does appear to closely match the DR Study through 2020 in its 2016 Reference case, it ceases any further increase past 2020. Separately, its 2017 Reference case does not match the DR Study at all and similarly flatlines past 2020. There is no explanation why DTE believes that all demand response potential will stagnate past 2021.

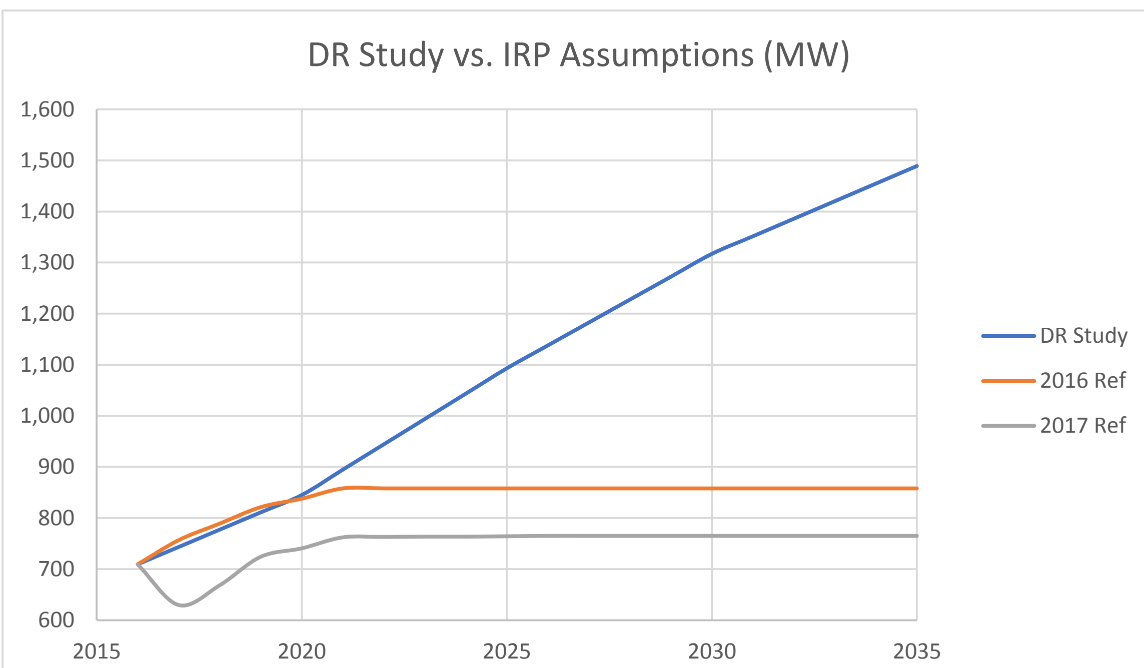


Figure 24 - DR Study vs. IRP Assumptions

Q. DID DTE ANALYZE ANY NEW DEMAND RESPONSE PROGRAMS THAT WERE DISCUSSED IN THE DR STUDY?

A. Yes. DTE analyzed a Bring Your Own Device (BYOD) program and a Programmable Communicating Thermostat (PCT). Both programs were analyzed as pilots with small budgets and deployment assumptions. As discussed later in Section IV of my testimony, data from STDE-5.7 shows that these programs provide capacity at very competitive prices. Further, these programs are currently being implemented in utilities across the country, so DTE would have ample opportunities to learn what has worked well and what pitfalls to avoid to quickly and effectively ramp up these programs.

Q. GIVEN THIS, DOES DTE INCLUDE ANY DEMAND REDUCTIONS FROM THE BYOD OR PCT PROGRAMS?

A. No. Neither program is included in DTE's 2016 or updated 2017 assumptions. (WP KJC-2, KJC-323.)

Q. HOW DOES DTE INCORPORATE THE RESULTS OF THE EE STUDY INTO ITS IRP PROCESS?

A. While the DR Study results are at best partially adopted, the EE Study results are incorporated in a convoluted and inappropriate manner. The EE Study calculated program potential savings that were tied to the implementation of specific programs at specific time frames. It reported savings in 2025 and 2035 relative to the baseline forecast. DTE used these figures not as inputs, but as a bizarrely fashioned "ceiling" on energy efficiency savings potential.

As seen in Figure 25 below, DTE's various energy efficiency sensitivities did not simply incorporate the EE Study results. Rather, each sensitivity assumed some fixed percentage increase in annual savings until the "ceiling" was reached, at which point the increase in energy savings fell back to the interpolated values based on the EE Study.

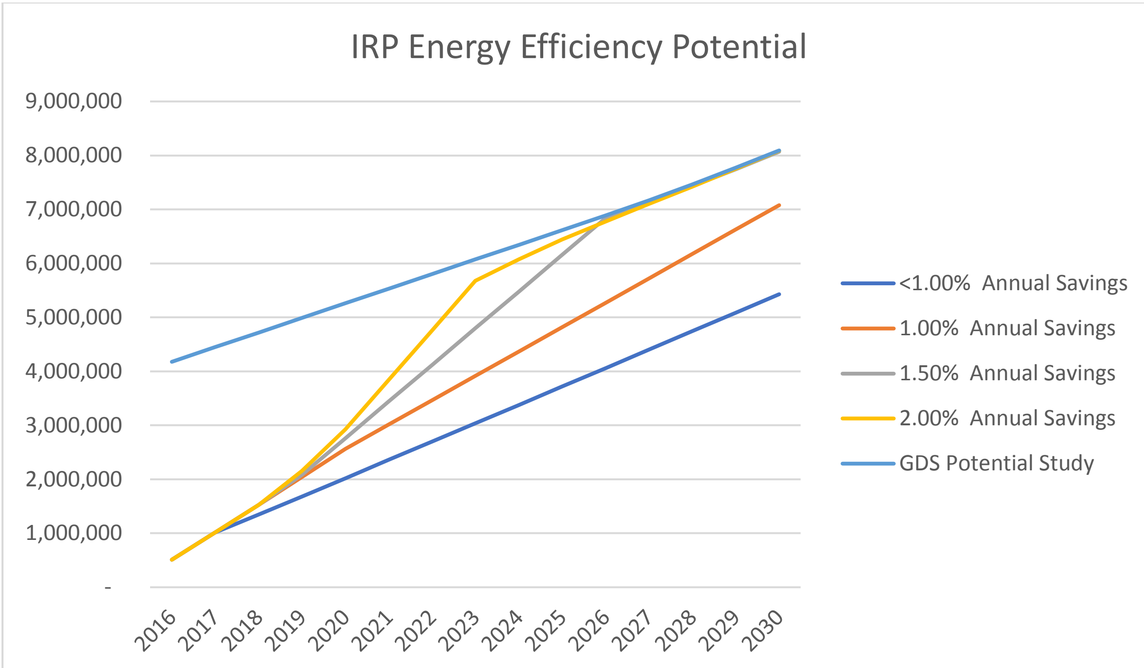


Figure 25 – IRP Energy Efficiency Potential

When these trends are extended through 2040 and translated into the actual energy sales forecast, the result is even more confusing. Figure 26 below uses data from MECNRDCSCDE-1.7 and shows the actual sales forecasts that were used in modeling under the various energy efficiency sensitivities. DTE first attempts to "back out" energy efficiency savings from its existing programs to produce a gross forecast with no energy efficiency savings. It then applies savings at various levels (e.g. 1.0%, 1.5%, 2.0%) to the gross forecast to produce new estimates on future energy use.

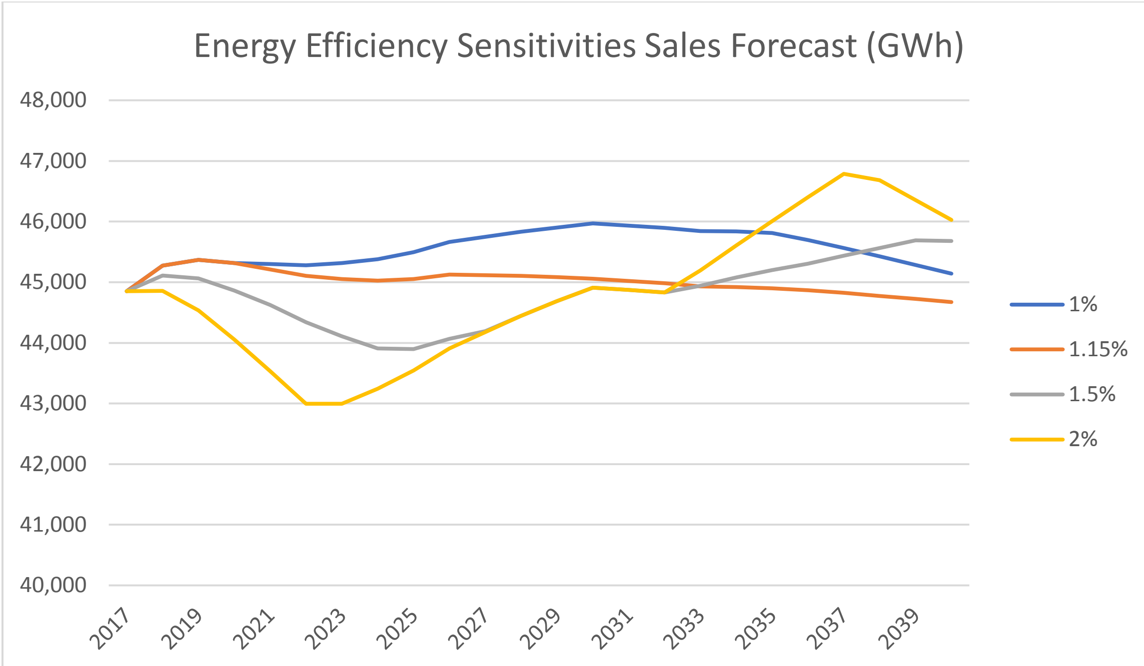


Figure 26 - Energy Efficiency Sensitivities Sales Forecast

One does not have to be an expert in energy efficiency to see that this interpretation of the EE Study results makes no sense. By simultaneously and arbitrarily ramping up energy efficiency savings to some predefined "cap", and then abruptly stopping all program implementation when savings are "used up," DTE produces a set of sales forecasts that are not supported by any reasonable underpinning.

These sales forecasts run counter to any logic. The most aggressive energy efficiency scenarios reduce sales early, but once savings are "used up," the forecasted energy use quickly increases. The result is that by 2030, the 1.15%, 1.5%, and 2% savings scenarios all converge. Even more absurdly, the 2% savings scenario actually results in higher usage between 2030 and 2040 as savings from measures implemented early in the analysis period expire.

Q. CAN YOU IDENTIFY SPECIFIC CONFLICTS BETWEEN THE GDS POTENTIAL STUDIES AND DTE'S INTERPRETATION OF THE RESULTS THAT PRODUCE THESE UNREASONABLE RESULTS?

A. Energy efficiency savings do not simply materialized. They are the result of dedicated programs that are designed to influence how consumers behave. Factors such as incentive levels, marketing, and program design all factor in to how quickly consumers adopt more efficient appliances and complete retrofits. These assumptions are core to the EE Study, and factors such as appliance saturation, adoption rate, and rebate levels all factor in to the incremental savings potential available each year. In short, the GDS Potential Study values in the figures above do not occur in a vacuum.

However, DTE assumes that energy efficiency savings can be arbitrarily ramped up or down without any consideration of how these results are actually achieved. DTE views the EE Study results as a ceiling that can be obtained with no programmatic adjustments. Further, it assumes that once the ceiling is reached (through some unnamed mechanism) all savings are exhausted. When asked about this obvious conflict, DTE had no convincing answer. When questioned about the causes that would produce the "gross forecast" without energy efficiency, DTE acknowledged that the values "were created as an arithmetic exercise, [therefore] no trends exist to explain it." (ELPCDE-4.11c, Ex. ELP-31 (KL-31)) When asked about what steps it assumed to increase the annual savings from 1.5% to 2.0%, it simply stated that "overall annual cost to achieve 2% is higher" and "therefore saturates the available achievable potential at a faster rate." (ELPCDE-4.14, Ex. ELP-32 (KL-32))

In short, DTE has no rational methodology for incorporating potential energy efficiency savings into its forecasts. It improperly assumes that the EE Study results are a hard and fast ceiling up to which energy savings can be increased arbitrarily and without additional effort, but beyond which incremental savings are impossible to obtain. It has no explanation for the math underlying the sales forecast in its IRP modeling. And it indiscriminately decides that no energy efficiency will exist after 2030, despite all indications that substantial quantities of savings can still be economically captured.

DTE's Own Analysis Shows the Superiority of the 2.0% Energy Efficiency Option

Q. SETTING ASIDE THESE ISSUES, WHAT DOES DTE'S OWN ANALYSIS OF ITS ENERGY EFFICIENCY SENSITIVITIES SHOW?

A. In its 2016 Reference case, DTE performed several different energy efficiency sensitivities. Among these were a 1.5% per year savings and a 2.0% per year savings. Table 4 shows the results of these two sensitives, including the total cost and benefits, net benefits, and utility cost test (UTC) test results.

	1.5% Savings	2.0% Savings	Delta
Total Costs	$945,046,780	$1,001,882,536	$56,835,756
Total Benefits	$5,006,396,711	$5,194,668,436	$188,271,725
UTC Ratio	5.30	5.18	-0.11
Net Benefits	$4,061,349,931	$4,192,785,900	$131,435,969

Table 4 - Energy Efficiency Savings 1.5% vs. 2.0%

Notwithstanding the many logical inconsistencies with DTE's incorporation of the EE and DR Study, DTE's own modeling shows that the 1.5% energy efficiency savings sensitivity that it ultimately selected produced $131 million less savings than the 2.0% energy efficiency savings sensitivity.

Q. DID DTE HAVE AN EXPLANATION FOR THIS DECISION?

A. Yes. It chose the 1.5% savings portfolio over the 2.0% savings portfolio in part because it had the highest UTC ratio. (ELPCDE-4.9, Ex. ELP-33 (KL-33))

Q. IS THIS EXPLANATION ACCURATE?

A. Yes.

Q. IS THIS EXPLANATION RELEVANT?

A. Not at all. Given that all of the portfolios that DTE compared are cost effective (i.e. all have a UTC > 1.0), the actual value of the UTC is irrelevant. When choosing between cost-effective portfolios, the objective must be to maximize the net benefits that accrue to DTE's customers. The 2.0% portfolio might have a slightly lower UTC ratio than the 1.5% portfolio, but even then it still returns over $5 in benefits for every $1 in cost. Further, it produces an additional $131 million in net present value benefits over the analysis period. If DTE's customers were asked whether they would prefer $131 million or a UTC ratio that is 0.11 higher, the answer would be obvious. There is simply no justification for failing to select the portfolio with the highest level of net savings.

Q. DID DTE OFFER OTHER EXPLANATIONS FOR ITS CHOICE?

A. Yes. DTE initially indicated that the 1.5% portfolio was "administered within a budget that is consistent with previous levels." (Dimitry direct at 23.) When pressed on the relevance of budget within the context of an IRP, DTE backpeddeled and states that the 1.5% portfolio was "consistent with previous level, [but] there was not a budget constraint." DTE continued to state that:

> A consistent budget supports multi-year planning and budgeting for the Company and its vendors and stability for the Company and vendors in managing work volume and associated staffing. The planned 1.5% level of energy efficiency supports steady progress over many years rather than quickly ramping up and then scaling back significantly when the energy savings potential is saturated (as occurs with the 2.0% level). Stability in offerings to customers and trade allies from year to year can have a significant impact on satisfaction and participation. (MECNRDCSCDE-1.3a, Ex. ELP-34 (KL-34))

Q. IS THIS ANSWER CONVINCING?

A. No. Instead, it reflects DTE's misinterpretation of the EE Study results. There is no need to quickly ramp up and then scale back significantly because energy savings potential does not hit a hard ceiling, despite DTE's assumptions that it does. If DTE wants to capture more program savings, it can adjust program designs and budgets. This headroom is seen in the large difference between the program achievable potential and the economic potential. While I do not suggest that DTE can capture 100% of the economic potential, DTE has made no effort to capture additional savings beyond the achievable potential found under its assumptions.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH DTE'S ENERGY EFFICIENCY ASSUMPTIONS.

A. While DTE commissioned – and its customers presumably paid for – two studies to investigate the level of energy efficiency and demand response reductions that could be obtained within its territory, it fails to appropriately apply their results. Demand response potential from the study is largely ignored, replaced by a trend that flatlines post-2020. DTE makes no effort to improve program performance or explore new opportunities that are common in other states. Energy efficiency potentials are grossly distorted in the IRP base forecast, with inaccurate assumptions that energy efficiency savings will simply "run out" at some point.

2017 IRP Update

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. In this subsection, I discuss DTE's 2017 IRP update and how some of the changes in assumptions might have affected the modeling. Despite major changes in the underlying assumptions, DTE did not perform a robust update to its core IRP scenarios and sensitivities. I also discuss in detail DTE's recently announced CO2 reduction goals, and how the Proposed Project (and two others like it) will make it more difficult for DTE to meet these goals.

DTE Makes Substantial Changes in its 2017 IRP Assumptions but Fails to Fully Analyze their Impacts

Q. FROM WHAT TIMEFRAME WAS THE DATA THAT WAS USED IN THE IRP TAKEN?

A. The PACE Global 2016 Reference AURORA input files are dated March 14, 2016, although the file itself was created on March 10, 2014. (WP KJC-51.) The Navigant Consulting report used for one of the many solar forecasts was published in Q2 2016.[69] The renewable energy assumptions for the Strategist input files are marked April 1, 2016. (WP KJC-48.) The PROMOD input file for the 2016 Reference case was created on December 9, 2014. (WP KJC-50.) Both GDS potential studies – Energy Efficiency and Demand Response – are dated April 20, 2016. This indicates that key pieces of information were probably compiled in late 2015 and early 2016.

Q. DID DTE PROVIDE A 2017 UPDATE USING MORE RECENT DATA?

A. Yes. While some modeling inputs such as GDP and population projections are reasonably stable year to year, others such as renewable energy projections can shift quite a bit in a short period of time. Additionally, the Legislature passed PA 342, which strengthened Michigan's Renewable Portfolio Standard and altered the requirements that DTE faced. DTE produced an updated 2017 Reference case incorporating these "latest assumptions." (Exhibit A4 at 218.)

Q. PLEASE DISCUSS THE MAJOR CHANGES BETWEEN THE 2016 AND 2017 DATA.

A. DTE discusses its many changes on pages 219 to 225 of the IRP report. These include:

- The 2017 peak demand forecast falls in the near term before increasing slightly past 2021.

[69] https://www.navigantresearch.com/research/u-s-distributed-renewables-deployment-forecast

- Energy sales fall in the near term before normalizing against the 2016 data from 2023 and beyond.
- Demand response assumptions are considerably lower in the 2017 update.
- Energy efficiency was assumed to increase to 1.5% per year rather than 1.15% per year.
- While the 2016 scenarios assumed a carbon price was available throughout the planning horizon, the 2017 updated pushed back any carbon price until 2027.
- Energy market prices are projected to be lower through 2026, at which point they increase beyond the 2016 figures.
- Market capacity prices are quite a bit lower in the 2017 update.
- DTE moved from a generic NGCC to a specific project.
- Gas prices are lower throughout much of the forecast, only surpassing the 2016 figures in 2035.
- Renewable deployment was modified to be in compliance with PA 342. Wind builds increased from 500 MW to 686 MW, while solar builds decreased from 100 MW to 60 MW.
- Solar capacity contribution was reduced from 50% to 41%.

In other words, almost every variable was changed. Notably, the 2017 update decreased demand response by 127 MW in 2017, 120 MW in 2018, and between 93 and 97 MW from 2019 forward. (WP KJC-2 and WP KJC-323.) DTE's shift from a generic CCGT to a specific model increased the size of the project by about 90 MW, reduced the heat rate by about 100 Btu/kWh, and incorporated a 12.5% reduction in costs to $924/kW from $1055/kW.

Q. WHY DID DTE REDUCE ITS SOLAR CAPACITY CONTRIBUTION FROM 50% IN THE 2016 CASES TO 41% IN THE 2017 CASES?

A. It indicated that the reduction was "based on actual solar performance of the DTE solar fleet from 2016, which was 39% firm." (ELPCDE-8.4b, Ex. ELP-35 (KL-35)).

Q. DID DTE'S CALCULATION FOR ITS 2016 PERFORMANCE HAVE SOME IRREGULARITIES?

A. Yes. In the attachment provided with the data request, many projects had long strings of 0 values in the meter reads, indicating no energy was being produced even when other facilities were registering production. One project showed 0 generation in 57% (158 of the 276) hours used in the analysis. Another appeared to be out for 36% of hours, and another for 28% of hours. All told, 9 projects representing 36% of the total capacity of DTE's portfolio recorded more than 20 zero generation hours. On a capacity-weighted basis, the total portfolio recorded 0 generation in 8.7% of hours in the middle of the afternoon in the summer.

Additionally, several of DTE's facilities did not appear to contain actual operating data. One of the larger facilities, labeled "DTE TDC 375KW", only reported hourly generation equal to 0, 189.7344, and 379.4688 kWh. Another only reported generation in perfect increments of 0, 64, 128, and 192 kWh. Given the wide variation in solar conditions over the course of three months, it is not feasible that a properly operating system would actually produce 3 or 4 different readings the entire summer.

Finally, the capacity values that were listed in DTE's data request did not all match those found in the IRP Report Table 6.7.2-1. For some plants, the difference was minor (for instance, GM Hamtramck was listed at 0.516 MW_{AC} in the response and 0.500 MW_{AC} in the table). But for two larger arrays (Ford Headquarters and Greenwood Solar), the response contained a much larger number than did the IRP Report. This resulted in a reduced capacity factor based on a larger system size.

Q. WERE YOU ABLE TO ANALYZE THE PERFORMANCE OF SYSTEMS THAT DID NOT HAVE THESE IRREGULARITIES?

A. Yes. I removed systems that had more than 20 zero generation hours or had fewer than 5 unique readings through the summer. For the remaining systems, I used the capacity figures as reported in the IRP Report. Using this data, the average capacity factor of the facilities for the hours in question was 44%, up from 39%. Although this value remains lower than the 50% default assumption, it should be noted than a number of DTE's projects were installed from 2010 to 2013. As discussed previously in my testimony, newer systems perform better than those installed during this time, and it would be reasonable to expect projects installed in 2018 and forward to perform better than systems which are in some instances 8 years old.

Q. DID DTE MAKE ANY CHANGES WITH RESPECT TO RENEWABLE ENERGY PRICES?

A: No. Notably, renewable energy prices were not updated between the 2016 and 2017 Strategist runs, despite a continued acceleration of price declines in solar.

Q. WERE THE IRP SCENARIOS AND SENSITIVITIES OTHER THAN THE REFERENCE CASE RUN WITH THE 2017 DATA?

A. No. All of the original scenarios and sensitivities other than the Reference case were performed only with the original 2016 data. Only the Reference case from the original set of scenarios was run with the updated 2017 values.

DTE did create a new 75% CO2 Reduction by 2040 sensitivity that it ran with 2017 data, but this was not designed to compare the performance of different scenarios and sensitivities. Rather, it was designed to explore a pathway that DTE suggests might be consistent with its long-term CO2 reduction goals.

Q. DOES THERE APPEAR TO BE A MAJOR ERROR IN DTE'S INPUT VALUES IN ITS 2017 CASE?

A. Yes. As discovered by Mr. Beach when reviewing the Strategist output from DTE's 2017 Reference case, it appears that DTE incorrectly modeled the heat rate of the two NGCC at 5,290 BTU/kWh rather than the 6,310 BTU/kWh that was used in PROMOD for the 2017 Reference case.

Although this may have been an innocent typo, it has a profound impact. By modeling the heat rate 16% lower than is appropriate, the two plants consume 16% less fuel to produce the same energy. This translates into a massive, but erroneous, reduction in the costs of the 2017 Reference case.

Q. DO YOU HAVE AN OPINION ON HOW THESE CHANGES IMPACTED THE MODELING RESULTS?

A. The heat rate error was discovered too late to quantify its impact, but given the quantity of natural gas that is consumed by the two NGCC, it likely swamps the impact from the other input changes.

Directionally, some of the input changes offset others. For instance, the 2017-2021 reduction in peak load and higher energy efficiency savings are muted by the reduction in demand response. A lower gas price forecast will tend to reduce the overall cost of the IRP relative to the 2016 figures, but the failure to use lower renewable energy price forecasts would miss cost reductions from the renewable builds. Because DTE only used the new inputs for a few scenarios, it is impossible to tell how these updates would have interacted with a broader range of scenarios. Further, by failing to update the solar and wind prices, despite all the indications that the price forecast should be reduced, it is impossible to see how higher renewable builds would have fared under more realistic assumptions.

Q. WHAT WAS THE RESULT OF THE REFERENCE SCENARIO WITH THE REFRESHED DATA INPUTS?

A. Under the new assumptions, the PVRR of the Reference scenario fell by more than $2 billion, or nearly 15%, from $15.8 billion to $13.6 billion. (Exhibit A-10 at 6.) I was not able to determine how much of this drop was caused by the changes to the input values and how much from the major error with the heat rate for the two NGCC. Nonetheless, the magnitude of this change suggests that these were not trivial updates to the input variables.

Despite many changes in the underlying data, DTE did not run any of the non-Reference scenarios and sensitivities using the new data. Rather, it found that since the output of the 2017 Reference case built the Proposed Project in the same year as the 2016 Reference case that this step would have been unnecessary.

Q. DO YOU AGREE WITH THIS ASSESSMENT?

A. No. DTE's 2017 Reference case suffers from the same myopic view of distributed resources, so even as the underlying inputs change, it was unlikely that they would produce an outcome substantially different than the 2016 Reference case. That said, DTE's failure to investigate how the updated assumptions affected the various scenarios is concerning. Given how many variables changed between the two scenarios, and that some critical values did not change, DTE should have run more sensitivities with the 2017 updated data.

After fixing the heat rate error, some of the assumptions could have had material impacts under different sensitivities. The reduction in demand response was considerable and based on a single data point on the performance of the D8 interruptible rate. Rather than try to address the lower-than-expected enrollment in this program, DTE simply dropped its DR forecast. (ELPCDE-5.14, Ex. ELP-36 (KL-36)) DTE's response to this single data point was very conservative, and it should have provided important information to evaluate how higher demand response participation would have impacted the results. Likewise, the 2% energy efficiency option produced superior results under the 2016 results, even with the questionable assumptions discussed above. The failure to update renewable energy cost projections, which were high to start with, is another issue.

The interaction of these three variables is something that DTE should have explored. The combination of almost 100 MW more demand response, an increase in energy efficiency MW, and lower renewable prices combined with earlier builds might have been able to delay the Proposed Project date, even under the assumptions biased against distributed resources. Given that DTE's cost of capital is higher than the inflation rate applied to the Proposed Plant cost, delaying the project saves money for customers. But we do not know whether or not this would occur, since DTE did not perform any additional runs with the updated data. Fortunately, Mr. Beach did perform such an analysis, and his results show that the Proposed Project can not only be delayed past 2022, but can be pushed out until 2027.

DTE's Long-Term CO2 Goals are Complicated by the Construction of the Proposed Project

Q. PLEASE DISCUSS DTE'S 2017 75% CO2 REDUCTION BY 2040 SCENARIO.

A. In May 2017, DTE announced a plan to reduce the Company's carbon emissions by more than 80% by 2050. In announcing the plan, DTE's Chairman and CEO Gerry Anderson said the following:

> Over the past two years we have studied the engineering and economics of Michigan's energy future very, very carefully. We have concluded that not only is the 80 percent reduction goal achievable – it is achievable in a way that keeps Michigan's power affordable and reliable. There doesn't have to be a choice between the health of our environment or the health of our economy; we can achieve both.[70]

The plan has checkpoints in 2030 (45% reduction) and 2040 (75% reduction). The latter of these was modeled as a sensitivity to the 2017 Reference case. This scenario retires Monroe Units 1 and 2 in 2039 and Units 3 and 4 in 2040, causing DTE's CO2 emissions to fall from around a 45% reduction to a 75% reduction in just two years. It also adds three combined cycle gas turbine plans in 2022, 2029, and 2039. The Fermi nuclear plant continues to run through the end of the model in 2040, although its license expires in 2045, meaning that DTE will have to either attempt to get another 20-year extension (bringing the life to 80 years) or replace this capacity and energy as well before 2050.

[70] http://newsroom.dteenergy.com/2017-05-16-DTE-Energy-announces-plan-to-reduce-carbon-emissions-by-80-percent#sthash.7eVQS4SF.dpbs

Q. WHAT DEGREE OF RENEWABLE BUILD OUT WAS ASSUMED IN THE CO2 REDUCTION SCENARIO?

A. There is a substantial increase in renewable energy in the CO2 reduction scenario as compared to the 2017 Reference scenario. As discussed above, DTE increases solar installations to 3,322 MW_{DC} and wind installations to 1,186 MW. These figures are significantly higher than the High Renewable scenarios, although most of the incremental renewable capacity is added beyond 2025.

Q. HAS DTE OPINED ON THE FEASIBILITY OF ATTAINING THE CO2 REDUCTION SCENARIO?

A. While Mr. Anderson appears confident that DTE has studied this issue and has concluded it is achievable while maintaining reliable and affordable power, DTE's response to a data request was more circumspect. When discussing the High Renewables scenario, which only plans 37% as much solar and 76% as much wind as the 75% CO2 Reduction scenario, DTE stated "[w]hile feasible in terms of a modeling exercise, a substantive assessment of the High Renewables sensitivity would require evaluation of customer cost impacts, project siting constraints and grid integration impacts." (ELPCDE-1.34, Ex. ELP-37 (KL-7))

When asked a follow up contrasting this more tepid response to Mr. Anderson's statement, DTE stated that "the Company believes that there are multiple possible paths – that are both achievable and affordable – that could lead to an 80% reduction in carbon emissions" and that while it "ha[s] laid out a possible path in the 75% % CO2 Reduction sensitivity … we have not concluded that this particular renewable resource plan is the most optimal". (ELPCDE-4.4, Ex. ELP-38 (KL-38))

Q. HOW MUCH FLEXIBILITY DO YOU BELIEVE THERE IS FOR DTE TO MEET ITS 2040 AND 2050 CO2 REDUCTION GOALS?

A. While the specific portfolio that attains these goals might be unknown, the broad strokes of a plan to hit 80% CO2 reductions are fairly constrained due to simple math and physics, unless DTE bases its plan on currently uneconomic, unproven, or unknown solutions.

Reducing CO2 requires a focus on energy production, rather than resource adequacy, since CO2 emissions are a function of the fuel burned over time rather than the amount of power produced at a single moment. To hit these deep CO2 reduction targets, certain things must happen under any scenario. Energy efficiency and demand response must be maximized starting immediately. All of DTE's large coal plants must be retired. Generation from natural gas plants will be the dominant source of CO2 emissions in 2040 and 2050, but those plants can only run as much as the CO2 goals allow. As a result, the balance of energy must come from zero-carbon resources such as solar, wind, nuclear, and energy efficiency.

At the same time, DTE must maintain sufficient capacity to keep its system reliable. Flexibility – both on the generation side and on the demand side – is key. As more variable resources such as solar and wind are introduced, matching supply with demand will require more attention. The ability for generators to respond quickly to changes in solar and wind generation, and to ramp their output up or down, is critical. Additional capacity resources and ancillary services capability from batteries, smart inverters, and synthetic inertia[71] can help smooth the changes in variable energy resources.

If DTE is allowed to pursue its Proposed Project, a substantial portion of DTE's future carbon budget will be locked in, and DTE will expose its customers to decades of natural gas costs and price volatility and stranded asset risks. Further, the operating

[71] Synthetic inertia is an enhanced operating characteristic that large wind and solar farms can provide. By using power electronics to control the output of these generators, the projects can mimic the benefits of the rotating mass inertia from conventional generators that helps maintain the frequency of the power grid under sudden changes of load.

characteristics of the Proposed Project are not necessarily the most critical as DTE works to integrate increasing quantities of renewable energy.

Q. HOW ROBUST IS DTE'S PLAN TO HIT ITS 2040 AND 2050 CO2 REDUCTION SCENARIOS IF THE FERMI NUCLEAR PLANT IS ABLE TO CONTINUE TO OPERATE TO 2050?

A. DTE's current plan as modeled in the 75% CO2 Reduction scenario requires the construction of three large natural gas combined cycle (NGCC) units. Data from WP KJC-387 shows how each unit is dispatched and how much CO2 is produced, but this data is not consistent with the data presented on page 226 of the IRP Report. While the IRP report shows the emissions falling to roughly 10 million tons in 2040, the model output results in 17.8 million tons because Monroe Units 3 and 4 are still operating at full output in 2040. If the emissions from these two units are removed, the modeling run produces 10.1 million tons, which appears to match the IRP Report. However, Monroe cannot both run and not run at the same time, so it is unclear if DTE's modeling results accurately reflect the scenario in the way that DTE suggests it does.

The Proposed Project makes it harder for DTE to meet its 2040 carbon reduction goals. WP KJC-390 indicates that the 2050 CO2 goal is 8.37 million tons, 17% lower than emissions after the last coal plant is retired. Each NGCC plant produces about 8,600 GWh and 3.25 million tons of CO2 at the capacity factors in the model. In fact, the three NGCC plants will produce 96.3% of DTE's projected post-Monroe-retirement CO2 emissions. Even if Fermi gets another extension on their operating license, DTE will have to find CO2 reductions from somewhere, and the only choice are the NGCC plants. The only way to hit the 2050 goal is to reduce the amount of energy – and thus emissions – that these units produce.

Assuming no loss in plant efficiency, to further shrink CO2 emissions to 8.37 tons, the output of the three plants would have to be reduced by 18%. This will create another challenge for DTE. When the remaining Monroe units close, they take their roughly 7,000 GWh, or 16%, of DTE's energy production with them. The additional 18% reduction in the three NGCC plants reduces energy output by another 4,600 GWh. Combined, this opens up an energy production drop of roughly 11,740 GWh that must be met through either energy efficiency or zero-carbon renewable generation

DTE appears to have accounted for the drop in generation from the Monroe units through the newly added renewable sources in its model. These sources provide 11,542 GWh by 2040. (WP KJC-389.) However, this does not fully close the gap caused by running the NGCC plants less. DTE's native load for 2040 in the model is 43,898 GWh. After removing the Monroe units and reducing the NGCC to hit the 2050 target, DTE generates 43,119 GWh. Assuming usage remains the same, this leaves a gap of 779 GWh that DTE must fill with zero-carbon resources. This is a non-trivial amount. It would require either 562 MW_{DC} more solar or 270 MW more wind at DTE's assumed capacity factors[72] on top of the 3,322 MW_{DC} of solar and 500 MW of wind already in the 75% Reduction Scenario. Alternatively, it would require a further 1.75% drop in absolute energy use from what is already modeled in scenario.

In summary, assuming that DTE could extend Fermi's operating license beyond 2045 to continue to provide nearly 20% of DTE's total energy through zero-carbon nuclear energy, construction of the Proposed Project limits DTE's future options to reach its publicly stated carbon reduction goals. In contrast, DTE could maintain future flexibility and better position itself to meet its goals by investing in more renewable energy sources, energy efficiency, and demand response programs now.

[72] 19% AC for solar and 33% for wind, per WP KJC-389.

Q. HOW DOES THIS SCENARIO CHANGE IF FERMI IS NOT ABLE TO OPERATE PAST ITS 2045 OPERATING LICENSE EXPIRATION?

A. Everything gets even harder. Fermi contributes 1,060 MW of capacity and 8,498 GWh of zero-carbon energy. While DTE could replace the capacity with peaking plants that do not run often, replacing the energy must be done with even more zero-carbon energy in order to maintain the CO2 reduction goals. Providing this amount of energy will require the equivalent of 6,688 MW_{DC} of solar or 3,209 MW of wind.

Q. HOW DO THESE FIGURES RECONCILE WITH DTE'S APPROACH TO THE IRP AND ITS CHOICE FOR THE PROPOSED PROJECT?

A. It is difficult if not impossible to reconcile DTE's long-term carbon emission goals with its view that the Proposed Project is the best way to start down this challenging path. In order to hit its 2050 CO2 reduction goals, DTE must think differently. Its 75% by 2040 plan risks stranded assets by constructing three NGCC plants that cannot run at their full capacity even with Fermi, and cannot be used to make up any energy or capacity shortfall if Fermi closes.

While the IRP DTE has submitted in this CON proceeding in support of the Proposed Project focuses on the near-term need for capacity, meeting its 2050 goals must be focused on procuring sufficient zero-carbon energy while developing flexible operating assets. The 80% reduction goal requires that only 52% of DTE's energy come from its NGCC and peakers – the other 48% must come from zero carbon sources. Right now, Fermi is meeting 19% of the 48% (that is, about 40% of the zero-carbon energy requirement), but its life beyond 2045 is uncertain.

Q. CAN DTE MEET ITS 2050 CO2 REDUCTION GOALS?

A. Yes. There are certainly pathways for DTE to obtain roughly half of its energy from zero-carbon sources by 2050 while maintaining a safe, reliable, and affordable system, but it must plan appropriately starting now to meet that goal. Incremental changes from today's current capacity and energy mix are unlikely to allow DTE to meet this goal.

Locking in a large part of its 2050 CO_2 budget with an asset that lacks the flexible operating characteristics needed in the future is not the right first step.

If DTE is serious about hitting this goal, as its CEO appears to be, the Company will have to rethink how it will serve its customers in the future. This is a process that many utilities across the country are undertaking in order to meet renewables targets and CO_2 reduction goals. Eventually retiring all of its coal plants is a necessary but insufficient step, but the plan detailed in the 75% CO_2 Reduction by 2040 scenario does not put DTE on a path to meet the 2050 goals if Fermi's operating license cannot be or is not economic to be extended.

Q. WHAT SHOULD DTE BE DOING NOW TO MEET ITS 2050 GOALS?

A. DTE must immediately reduce its demand and energy needs through energy efficiency and demand response. Estimates suggest that half of the buildings that will be in use in 2050 are already built, and nearly all buildings that are constructed in the near future will be in use in 2050, so there is no time to delay on improving efficiency in the built environment.[73] Load will need to be more flexible and responsive to incorporate the large quantities of renewable energy that is needed. If Fermi closes, even more wind and solar must be deployed. Incorporating that much variable renewable energy will require rethinking how DTE's distribution network is structured and operated, and since those assets have decades-long life spans, DTE must start considering these changes today.

DTE's plan to construct its Proposed Project does little to solve these long-term challenges and increases the risk of stranded assets whose costs will fall squarely on DTE's customers. The last thing that the 2040 and 2050 carbon reduction pathway needs is to lock in a massive, centralized, CO_2-emitting asset in the next five years. There are alternative, zero-carbon approaches that can be used to meet the short-term capacity

[73] https://aceee.org/sites/default/files/ultra-low-energy-0717.pdf

needs while preserving options for the future. For instance, a portfolio like the one described by Mr. Beach will obviate the need to build the Proposed Project until 2027 by replacing it with more energy efficiency, demand response, solar, and wind – and will do so at a lower cost.

Q. DID DTE MODEL ANY SCENARIO THAT WAS SIMILAR TO THE ONE PRESENTED BY MR. BEACH?

A. No. As discussed earlier, DTE did not pursue any scenario with early renewable builds and more aggressive energy efficiency and demand response resources. While I do not believe that Mr. Beach's proposal is explicitly designed with DTE's 2040 or 2050 carbon reduction goal in mind, it is clearly a better first step towards that result than DTE's own proposal.

DTE's Presentation of the Proposed Course of Action's Financial Impacts is Misleading

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. In this subsection, I critique DTE's financial analysis of the Proposed Plan in which it compares revenue requirements against a "No Build" scenario. Despite acknowledging that the No Build scenario is not a realistic benchmark against which to compare the Proposed Plan, it is the only data point that DTE presents. DTE's modeling appears to contain a serious error related to the efficiency of the new NGCC, and even without this error, its own analysis shows the Proposed Project is a bad deal for its customers. Overlooking this issue, DTE makes the Proposed Plan appear more cost effective than it is by using overstated capacity costs. Further, DTE is unable or unwilling to separate the impact from a second NGCC unit in its analysis, resulting in a substantial overstating of the benefits associated with the Proposed Plan at issue in this CON proceeding. Finally, some of benefits in DTE's analysis come from updated CO2 price assumptions that only impact post-2027 revenues and have nothing to do with meeting DTE's short term capacity needs.

DTE's No Build Scenario is – by Its Own Admission – a Flawed Benchmark

Q. PLEASE DISCUSS DTE'S PRESENTATION OF THE FINANCIAL IMPACTS OF THE PROPOSED COURSE OF ACTION.

A. Witness Chreston spends very little of his testimony discussing the financial impact on DTE's customers of the Proposed Course of Action (Proposed Plan), which includes the construction of both the Proposed Project and a second NGCC in 2029, along with other renewable energy and energy efficiency investments. The last two pages of his testimony introduce Exhibits A-9, the Proposed Project Revenue Requirement Net PSCT Impact. This document, as presented in Mr. Chreston's testimony, contains a snapshot of the impact of the project in 2022 and 2023, with the latter representing the first full year of commercial operation. Most of the pages of this exhibit compare these two years.

However, to fully understand the impact of the Proposed Plan, one must analyze the impact over the full 2016-2040 period to account for all the changes in DTE's plan. To do this, Mr. Chreston developed Exhibit A-9 that contains annual revenues and costs for its Proposed Plan as well as a No Build scenario under its 2017 Reference case assumptions.

As far as I can tell, this is the only instance in Mr. Chreston's direct testimony or sponsored exhibits (including the IRP Plan) that contains annual information comparing the Proposed Plan against any other alternative. Further, it is the source for Mr. Chreston's testimony that the Proposed Plan is "$663 million less expensive than the 'No Build' option" and that the Proposed Project "shows a benefit to customers of approximately $33 million" in its first operating year. (Chreston Direct at 59 and 64.)

Q. WHAT IS THE NO BUILD SCENARIO?

A. The No Build scenario is one where the major assumptions, such as load forecast, fuel prices, renewable generation builds, and so on, are consistent with the 2017 Reference scenario, but rather than build the Proposed Project in 2022 and a second NGCC in 2029, DTE assumes that market purchases will be used to make up any capacity and energy shortfalls. DTE uses this as the "baseline" against which the revenue requirement of the Proposed Plan is judged, with the difference purporting to be the benefit of following DTE's recommendations in this proceeding.

Q. DOES DTE PROVIDE CONFLICTING INFORMATION ON THE FEASIBILITY OF THE NO BUILD SCENARIO?

A. Yes. In one part of his testimony, Mr. Chreston states that the No Build scenario "would not be feasible or prudent" based on DTE's assumptions about import capability and availability of market capacity for purchase. (Chreston Direct at 22.) Later, however, Mr. Chreston notes that the No Build scenario is "not economically viable" compared to the Proposed Plan, in part because he assumed a "far tighter market" and that "capacity prices reach CONE early in the study period." Together, the result of these assumptions is "that purchasing a substantial amount of energy and capacity from the market would be very costly and risky for customers." (Chreston Direct at 59). There of course is a difference between "not feasible or prudent" and "not economically viable … and very costly and risky for customers."

Q. DOES DTE OFFER ANY ADDITIONAL INFORMATION TO CLARIFY THIS DISCREPANCY?

A. Yes. When asked in a data request about the No Build scenario, DTE indicated that it included the No Build scenario in response to the Commission order to include "[d]escriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility or significant investment in an existing facility, that were considered, including a **"no-build" option**, and the justification for the choice of the proposed project." (ELPCDE-9.5i, Ex. ELP-39 (KL-39), emphasis in data request response but not in underlying referenced document.) Mr. Chreston continued:

> Since such a large amount of capacity purchases would be required throughout the "No Build" planning period to meet the DTE LCR/PRMR requirements, it is reasonable to assume that a capacity price of CONE which is representative of the MISO Capacity Deficiency Charge or the equivalent cost of someone building a large amount of capacity for DTE's benefit. (ELPCDE-9.5i, Ex. ELP-39 (KL-39))

Q. WHAT IS YOUR RESPONSE TO THE CONTRADICTORY INFORMATION PRESENTED ABOUT THE NO BUILD SCENARIO?

A. To some degree, DTE is trying to have it both ways. On the one hand, it presents the No Build scenario as unworkable, forced upon it only because of the Commission's requirement. On the other hand, it chooses to present the only meaningful year-to-year financial comparison that utilizes up-to-date information as a contrast between its Proposed Plan and the No Build scenario.

Q. IS THERE A MORE MEANINGFUL COMPARISON THAT DTE SHOULD HAVE ALSO PERFORMED?

A. Yes. In my view, DTE should have analyzed a portfolio that combined more renewable energy, energy efficiency, and demand response that still met the majority of DTE's capacity obligation through in-state resources. It would have been much more instructive to perform an additional comparison of DTE's Proposed Plan against a portfolio similar to the one developed by Mr. Beach, rather than only comparing it to a scenario that DTE does not believe is reasonable and prudent. However, for reasons discussed previously, DTE has failed to do this. Had it performed this analysis, DTE would have found that its Proposed Plan is not the best result for its customers, just as Mr. Beach did.

DTE's Own Analysis Shows the Proposed Project is a Bad Deal for Customers

Q. PUTTING ASIDE YOUR ISSUES WITH DTE'S CAPACITY COST ASSUMPTIONS, WHAT DOES DTE'S OWN ANALYSIS SHOW ABOUT THE FINANCIAL IMPACT OF ITS PROPOSED PROJECT?

A. The Proposed Project is a net cost to DTE's customers until at least 2030. DTE is able to recover CWIP from its customers prior to the operation of the Proposed Project. From 2016 to 2021, the annual revenue requirement needed to serve capital-related costs such as capital costs, property tax, and insurance increases from nothing to $106.5 million. During this time, DTE customers will have paid a total of $220.8 million for a plant that has not produced a single kWh of energy nor offset a single market purchase.

By the time that the Proposed Project comes partially online in 2022 and finally starts to offset market purchase expenses, DTE customers will have paid a net of $267.9 million. Between 2023 and 2027 (the year before major expenses for the second NGCC start accumulating), DTE customers only recoup $178.3 million in benefits, far short of the amount that they have paid in for the plant. On a net present value basis, DTE's customers are in the hole for a maximum of $189.3 million in 2022, are still out $97.2 million at the end of 2027 due to the costs of Proposed Project, and do not break even until the end of 2030 when benefits from the second NGCC kick in.

Figure 27 below shows the annual costs associated with capital-related expenses and the annual benefits from net O&M and sales revenue, which when combined result in the net annual revenue requirement. The dashed line converts the net annual revenue requirement to a cumulative net present value of the revenue requirement, showing the running total cost paid (negative values) or benefit received (positive values) from DTE customers' perspective.

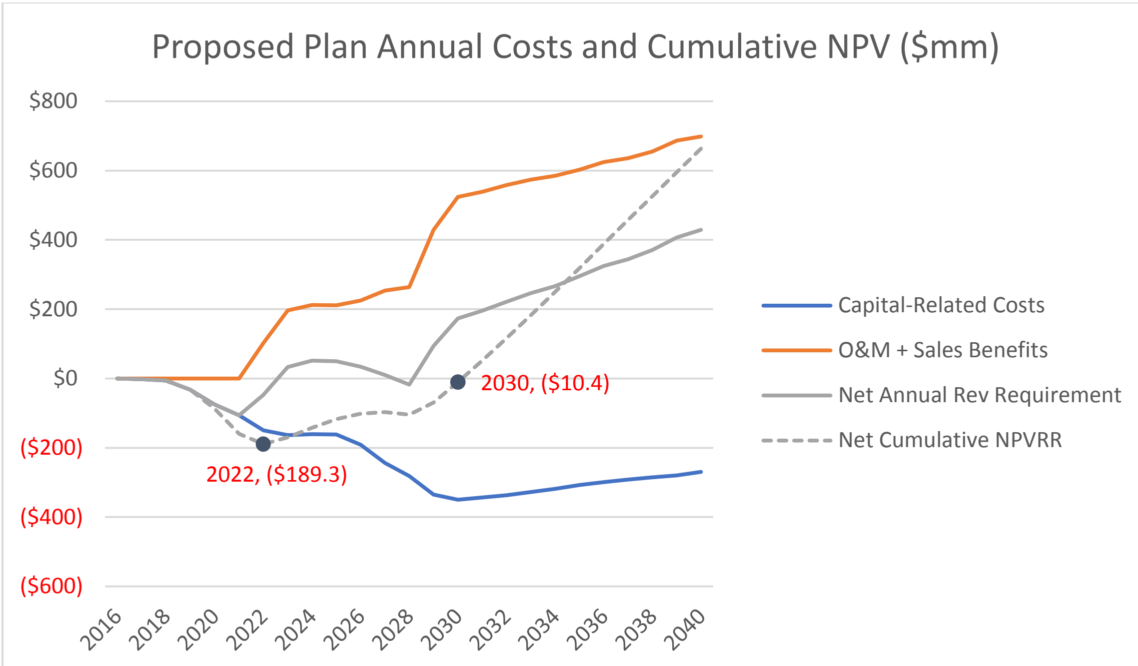


Figure 27 - Proposed Plan Annual Costs and Cumulative NPV

Q. DOES THE HEAT RATE ERROR YOU REFERENCED EARLIER IMPACT THIS ANALYSIS?

A. I believe that it does, although the error was discovered too late to ask DTE to confirm it and update its workpapers. However, by comparing generation and fuel cost figures between the 2016 and 2017 Reference cases, it appears that the 2017 values are substantially lower than would be anticipated due to the drop in natural gas prices used in the updated scenario.

I compiled generation and fuel costs from the new NGCC, along with natural gas price forecasts, for both the 2016 and 2017 cases. When one adjusts the 2016 fuel cost purchases downward to reflect the lower 2017 prices, the heat rate for the NGCC in the 2017 scenario is roughly 12% lower than in the 2016 scenario. The result is that the 2017 Reference case as used in the financial comparison understates fuel purchase costs from the two new NGCC facilities by roughly this same amount.

Given how much generation comes from the two NGCC, this has a substantial impact. Between 2023 and 2040, these plants consume nearly $10 billion in fuel under the 2017 scenario. Correcting the heat rate to the proper value increases this by $1.4 billion.

Q. HOW DOES THIS IMPACT THE ANNUAL COSTS AND CUMULATIVE NPV?

A. It adds to the cost of the Proposed Plan and further deepens the hole customers find themselves in and lengthens the time needed for the project to pay its customers back. I have updated the analysis below in Figure 28, with the heat rate fix lines in lighter colors. With this adjustment, DTE's customers are out $245.6 million on a net present value basis before the plant starts earning money. They remain under water until 2035, well after the second plant has started operation.

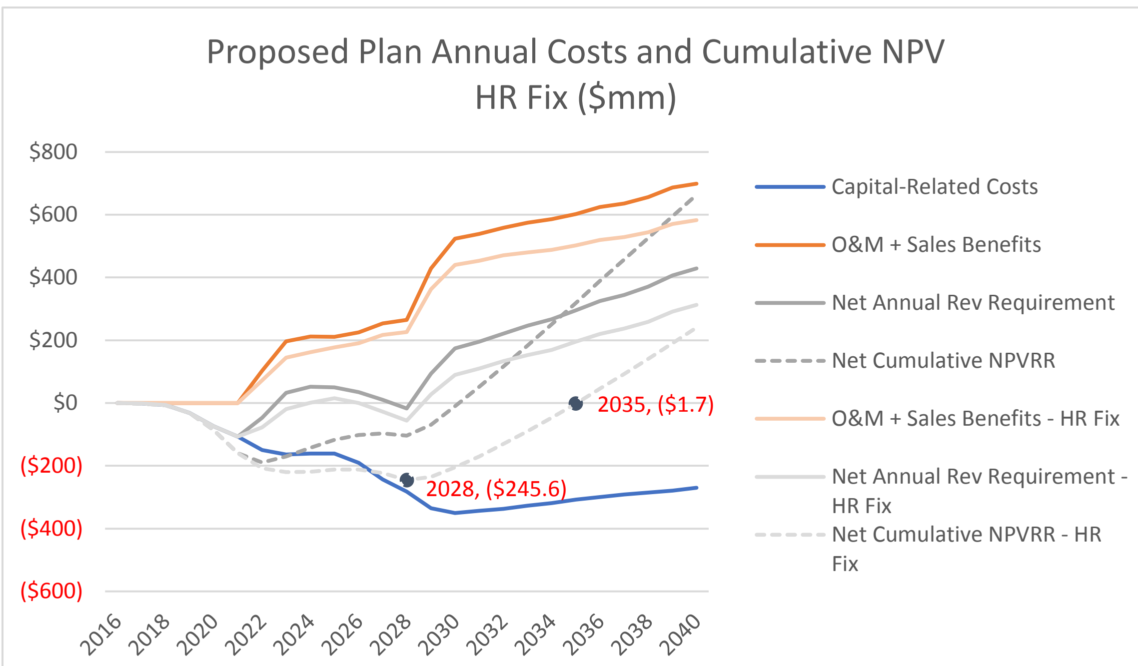


Figure 28 - Proposed Plan Annual Costs and Cumulative NPV w. Heat Rate Fix

Q. WHAT ARE YOU OBSERVATIONS ABOUT DTE'S ANALYSIS PRESENTED IN EXHIBIT A-9?

A. The Proposed Project, when viewed in isolation, is simply a bad deal for DTE's customers. Under DTE's own original analysis, they pay out hundreds of millions of dollars for the project before it starts to operate, and still do not recoup the investment on a non-discounted basis until 2030. Even then, it takes net sales revenues from the second NGCC (which include the previously discussed overstated capacity costs) to flip DTE's own analysis into the black. This problem is further exacerbated when the heat rate for the NGCCs are updated.

DTE's Capacity Cost Assumptions are Unrealistic

Q. DESPITE THE PROBLEMATIC NATURE OF COMPARING THE PROPOSED PLAN TO THE NO BUILD SCENARIO, DID YOU EXAMINE DTE'S ASSUMPTIONS EMBEDDED IN ITS ANALYSIS?

A. Yes. Flawed as it is, given that this comparison is the only one offered by DTE to explain the financial benefits of the Proposed Plan, it merited additional consideration. I examined the analysis underlying both the Proposed Plan schedule and the No Build schedule and found some problematic assumptions.

Q. WHAT DOES DTE CLAIM THE BENEFITS ASSOCIATED WITH THE PROPOSED PLAN ARE COMPARED TO THE NO BUILD SCENARIO?

A. DTE calculates that the NPV of the revenue requirement of the Proposed Plan is $663.1 million lower than that of the No Build scenario.

Q. DO YOU AGREE WITH DTE'S CALCULATION?

A. No. There are two reasons why this calculation inaccurately reflects the impact of the Proposed Plan. The first is that DTE grossly overstates the cost of purchasing capacity on the market over the course of the analysis in the No Build scenario, essentially double counting the cost of purchasing energy and assuming no market reaction to a perpetual shortage of capacity. The second is that the revenue requirement reduction from the 2017 Reference case derives much of its benefit from the retirement of the Belle River coal plants and the construction of a second NGCC facility in 2029, neither of which are attributable to the Proposed Project.

Q. PLEASE EXPLAIN DTE'S ASSUMPTIONS FOR CAPACITY COSTS IN ITS ANALYSIS.

A. Exhibit A-9 draws data from WP KJC-346, which in turn draws data from WP KJC-375. WP KJC-375 is a narrative analysis by PACE Global explaining its methodology for calculating capacity costs in MISO Zone 7 (i.e. Michigan). PACE calculates two capacity values in its analysis. The first represents the estimated value of capacity as reflected by the fundamentals of cost and tightness of supply and demand, represented by an estimate of MISO's Planning Reserve Margin Requirement (PRMR).[74] In the near term, Zone 7 has capacity beyond its PRMR, leading PACE to predict lower capacity values. In the medium-term and long-term, PACE projects the Zone 7 PRMR to stabilize around 15%, with some year-to-year variations, indicating a balance in supply and demand.

In the same document, PACE projects the Net CONE for Zone 7, or net cost of new entry. This value represents the revenues needed to support the construction of a new NGCC plant in the zone after deducting revenue from the energy and ancillary services markets. That is, if it takes $100/kW-year to build a new NGCC (i.e. Gross CONE), and the plant can be expected to earn $45/kW-year through sales of energy and ancillary services, then the residual capacity cost or Net CONE is $55/kW-year. This value is independent of the actual tightness of the capacity market but rather based on the administratively determined construction costs of a typical plant and forecasts of revenue from the energy and ancillary services market.

PACE points out that its analysis does not attempt to predict the outcomes of MISO's capacity auction, which can be influenced by market participant behavior as

[74] The PRMR is the amount of capacity that is required to keep the loss-of-load expectation to 1 day in 10 years. It is calculated annually for each zone based in load in the zone as well as the ability to import capacity from neighboring zones. The most recent study pegs the MISO-wide PRMR at 15.8% of installed capacity.

much as cost and revenue fundamentals. Rather, its projections for the value of capacity and Net CONE represent fundamental-based forecasts. Further, since PACE assumes that the supply and demand balance fairly well through the analysis period, the projected capacity price is very near the Net CONE price.

Q. DOES DTE USE THESE VALUES IN WP KJC-346?

A. It does use the estimate value of capacity in its 2017 Reference case, but it does not use the Net CONE in its No Build case. Rather, DTE uses a forecast entitled "2022 CONE" for the No Build case, which it confirmed corresponded to MISO's Zone 7 2017 Gross CONE adjusted for inflation. (ELPCDE-9.5b, d, and f, Ex. ELP-40 (KL-40)) This forecast uses the same capacity values as the 2017 Reference case from 2016 to 2021, but then switches to a value of $94.90/kW-year (in 2016 dollars) that is inflated to the appropriate year in the forecast. (WP KJC-346.) The three projections are shown in Figure 29 below, presented in nominal dollars based on DTE's inflation assumptions.

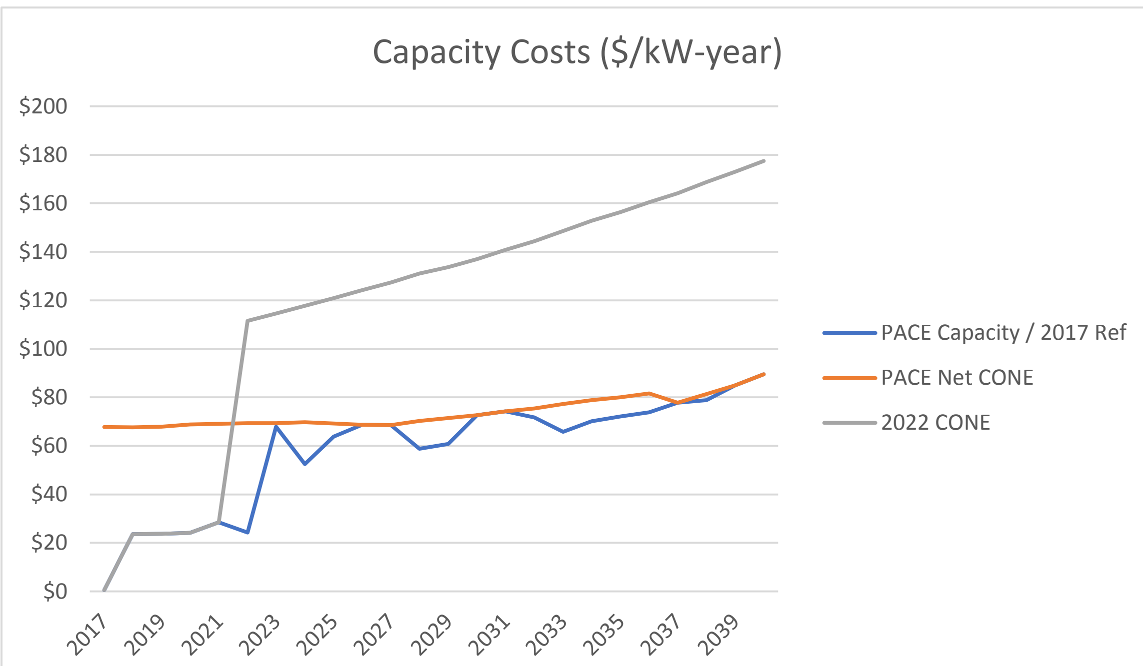


Figure 29 - Capacity Costs

Q. DOES DTE PROVIDE AN EXPLANATION FOR WHY IT DOES NOT USE THE PACE NET CONE FIGURES?

A. Yes. In response to a data request, DTE stated that the "large capacity purchase requirements in the 'No Build' sensitivity was forecasted to trigger the MISO Capacity Deficiency Charge which is based on Gross CONE." (ELPCDE-9.5e, Ex. ELP-41 (KL-41))

Q. IS THE MISO CAPACITY DEFICIENCY CHARGE BASED ON GROSS CONE?

A. Yes, although it is not equal to Gross CONE. MISO sets the Capacity Deficiency Charge equal to 2.748 times Gross CONE.[75] Alternatively, if DTE were to account for all of its PRMR through the auction, but not enough capacity cleared, then it would pay for capacity at the Auction Clearing Price set at Gross CONE rather than the Capacity Deficiency Charge.[76] DTE does not clarify which of these scenarios it envisions occurring in the No Build option, but it does not appear to have accurately modeled the Capacity Deficiency Charge as suggested by its data request response.

Q. IS DTE'S ASSUMPTION THAT CAPACITY COSTS WILL REMAIN AT GROSS CONE FOR 19 CONSECUTIVE YEARS REASONABLE?

A. No, and rather stunningly, DTE admits as much. When asked whether DTE believes that the MISO capacity market construct will fail to incent new entry of either generation assets, storage assets, or transmission assets when prices remain at CONE for 19 consecutive years, it simply replied "No" and referred back to its previous answer that the No Build scenario was not reasonable or prudent. (ELPCDE-9.5j, Ex. ELP-42 (KL-42)) Included in that previous answer was that "it is reasonable to assume that a capacity price

[75] https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/SAWG/2015/20151029/20151029%20SAWG%20Item%2005%20Capacity%20Deficiency%20Charge%20Clarification.pdf

[76] Id.

of [Gross] CONE which is representative of the […] equivalent cost of someone building a large amount of capacity for DTE's benefit." (ELPCDE-9.5i, Ex. ELP-39 (KL-39))

Q. IF SOME MARKET PARTICIPANTS WERE TO DEVELOP A LARGE AMOUNT OF CAPACITY FOR DTE'S BENEFIT, WOULD CAPACITY COSTS REMAIN AT GROSS CONE?

A. No. By definition, Gross CONE is the complete revenue requirement needed to construct a hypothetical new resource. DTE's assumption that cost might temporarily rise to the level of Gross CONE in a capacity shortfall situation is reasonable. However, once the capacity resource is built and is available for purchase, it would not be able to command the scarcity price of Gross CONE. In fact, depending on how large the resource is compared to DTE's needs, it might not be able to command much price at all.

In its development of capacity costs, PACE assumes that capacity supply and demand are well balanced and very near the reserve requirement. Figure 29 above predicts that capacity prices in this situation will hover near – but not exceed – Net CONE prices of roughly $70-80/kW-year. However, MISO's capacity auctions show that when the reserve requirement is met, capacity prices can be much, much lower.

In fact, the most recent auction for 2017/18 resulted in capacity in Zone 7 clearing for a mere $0.55/kW-year, following the 2016/17 auction results of $26.28/kW-year and the 2015/16 auction result of $1.27/kW-year.[77] Meanwhile, DTE forecasts that market capacity purchases in the No Build option will cost $111.50/kW-year in 2022 and increase to $137.04/kW-year in 2030 before reaching $177.50/kW-year in 2040.

[77] MISO PRA Detailed Reports, converted from $/MW-day to $/kW-year, available at https://www.misoenergy.org/Library/Pages/ManagedFileSet.aspx?SetId=2054

Q. IF GROSS CONE IS NOT THE MOST APPROPRIATE VALUE TO USE IN THIS ANALYSIS, WHAT SHOULD BE USED INSTEAD?

A. It is difficult to predict how Zone 7 would stabilize in a No Build scenario. While I strongly disagree with DTE's assumptions that no capacity will be developed and market purchases will remain at Gross CONE throughout the analysis period, I also recognize that MISO's capacity auction results are to an extent not reflective of the regulatory structure in Michigan and might not be the best proxy either. This leaves two options that are readily available in this proceeding – PACE's fundamentals-based capacity prices and its Net CONE forecast. Of these two, Net CONE is more conservative (i.e. more expensive), so I will use it for the remainder of this analysis.

Q. WHAT IS THE RESULT WHEN THE NET CONE FIGURES ARE USED IN THE REVENUE REQUIREMENT CALCULATION?

A. When Net CONE capacity figures are used, the net benefit of the Proposed Project changes to a net cost. The original net benefit of $663.1 million represented about a 5% increase in cost between the two scenarios ($12.6 billion vs. $13.3 billion). Capacity prices from market purchases are a major driver of the price difference between the two scenarios. Figures 30 and 31 below show the breakdown of revenues and costs from the Proposed Plan and No Build scenarios. The negative values for Energy Purchase in the Proposed Plan represent sales of excess energy into the market for which DTE collects revenue to offset its costs. The No Build chart shows market purchases at both 2022 CONE as used by DTE as well as at Net CONE as calculated by PACE.

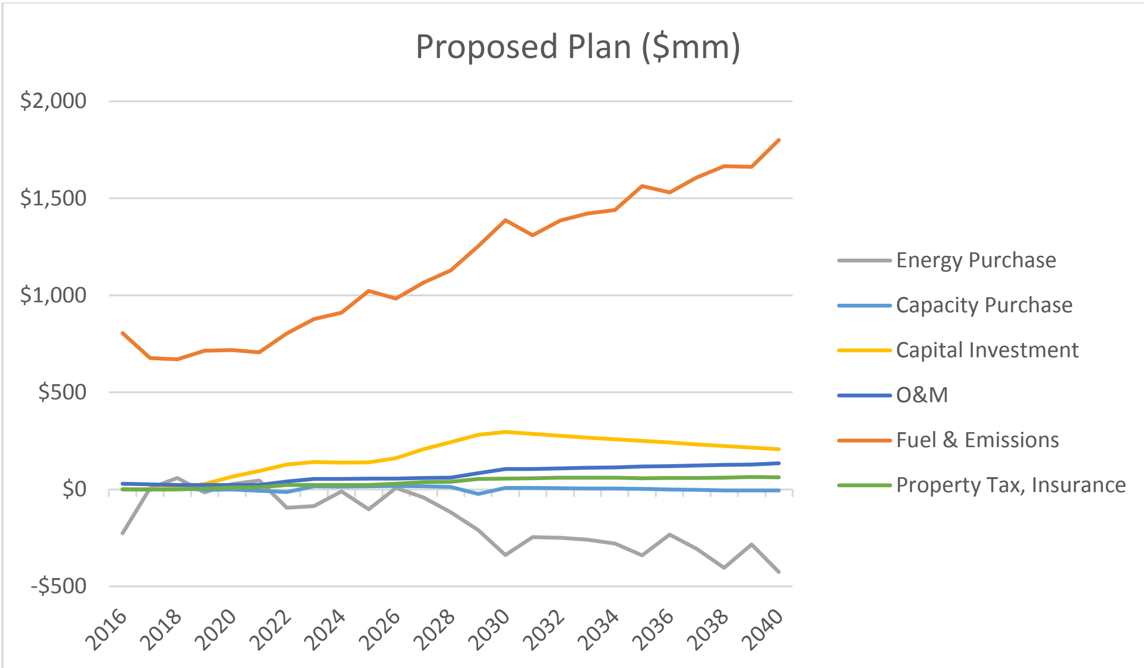


Figure 30 - Proposed Plan Revenues and Costs

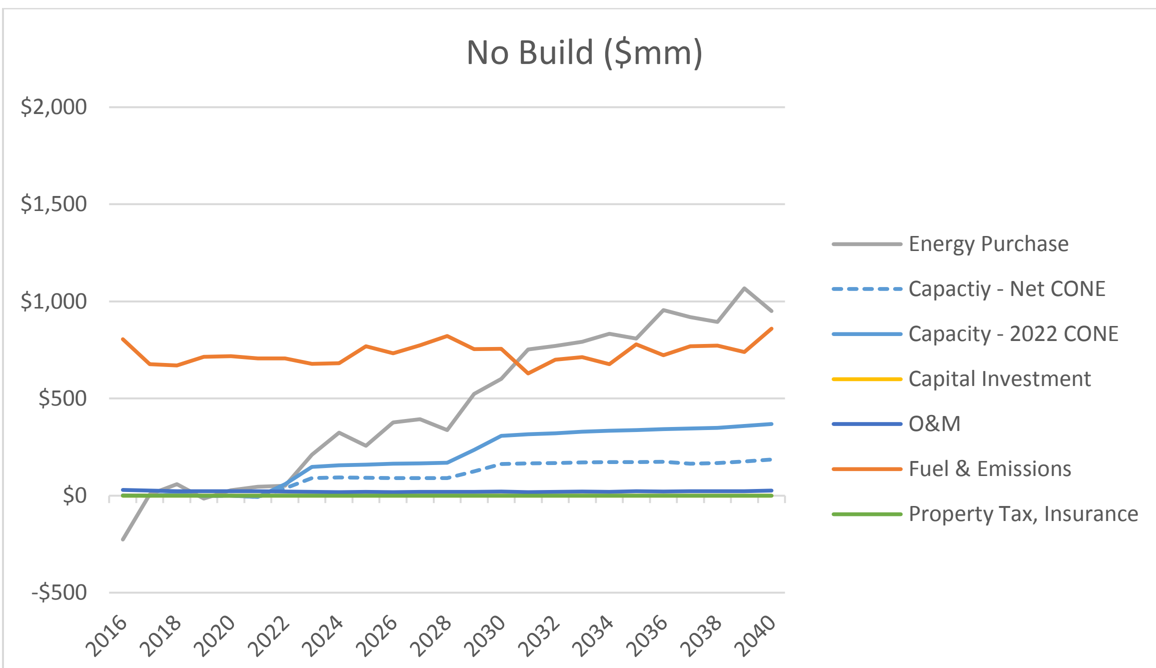


Figure 31 - No Build Revenues and Costs

Q. HOW DOES CHANGING THE CAPACITY COST IMPACT THE NPV OF THE REVENUE REQUIREMENT BETWEEN THE SCENARIOS?

A. When the NPV of these revenues and costs are calculated over the analysis time period, one can compare these categories directly. As expected, the major difference between the two scenarios is a substitution of costs from Fuel & Emissions expenses (to run the new plants) to Energy and Capacity purchases (to buy from the market). In Figure 32 below, I combined Fuel & Emissions costs with Energy Purchases into a Net Energy Expenses category.

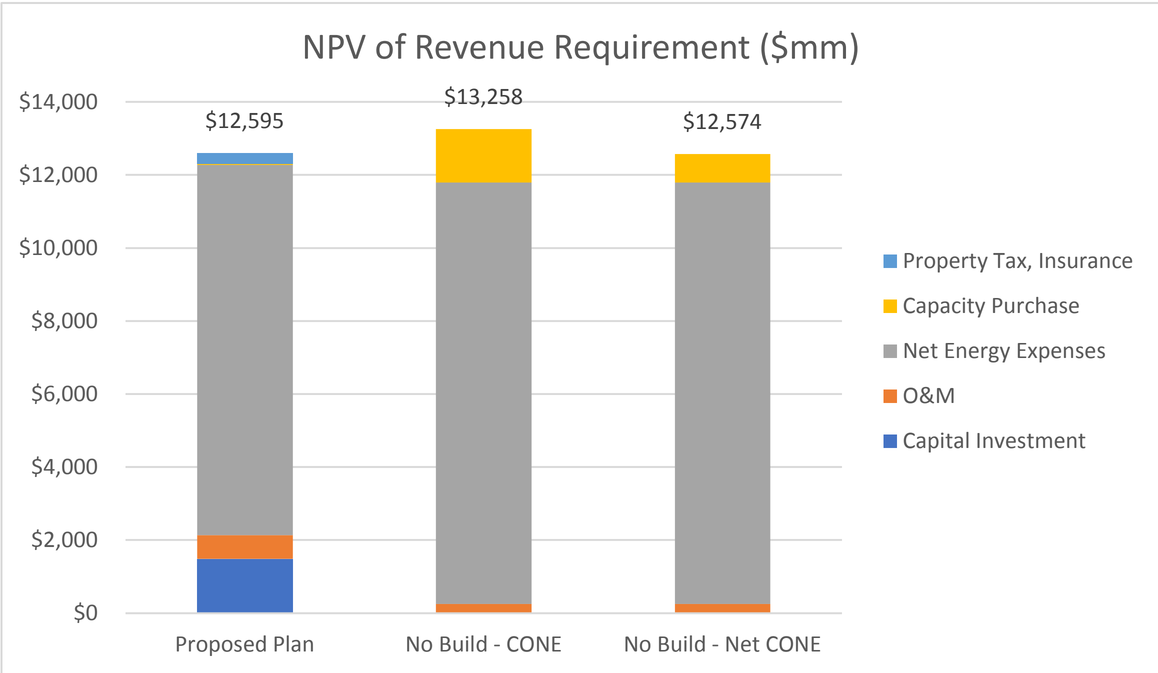


Figure 32 - NPV of Revenue Requirement

By making a simple and appropriate adjustment to the capacity costs, the Proposed Plan under the 2017 Reference case assumptions shifts from a net benefit for customers of $663 million to a net cost to customers of $21 million.

It is worth noting how much of cost of the Proposed Plan in Figure 32 above is locked up in net energy expenses. Over the analysis period, 80% ($10.1 billion out of $12.6 billion) of the costs are variable expenses that can and will shift based on fuel prices. After the heat rate error is fixed, this percentage increases even further. Mr. Beach discusses the volatility risk that customers are exposed to by the Proposed Project in more detail, but building or purchasing more solar and wind projects with zero variability in fuel prices will help reduce this exposure of DTE's customers.

DTE's Financial Analysis Incorrectly Includes Benefits from a Second NGCC Plant

Q. WHAT IS YOUR SECOND CONCERN ABOUT HOW DTE DISCUSSES THE FINANCIAL IMPACT OF THE PROPOSED PLAN?

A. The Proposed Plan is greater in scope than the Proposed Project. Some of these changes, such as the deployment of renewable energy and energy efficiency to meet current statutory requirements, are appropriate to consider in both cases. However, DTE also assumes the retirement of Belle River, one of its major coal plants, in 2029, and replaces this capacity with a second new NGCC in the same year. Neither of these actions are part of the CON for the Proposed Project. However, by including this second plant in its financial impact projections, DTE muddies the waters regarding which benefits are due to the Proposed Project and which are due to the retirement of Belle River and the construction of the second NGCC plant.

Q. WAS DTE ASKED ABOUT THE PRESENCE OF THE SECOND NGCC IN THE PROPOSED PLAN?

A. Yes. DTE was asked in a data request to duplicate Exhibit A-9 without the second NGCC unit. It indicated that this analysis did not exist. (ELPCDE-3.8, Ex. ELP-43 (KL-43))

Q. HOW PROBLEMATIC IS IT THAT DTE DID NOT PERFORM ANY ANALYSIS ISOLATING THE IMPACT OF THE PROPOSED PROJECT?

A. It is extremely problematic. DTE is requesting a CON based on its Proposed Project, yet it presents financial results based on building two NGCC. As discussed below, much of the supposed benefit of the Proposed Plan is actually from factors other than the Proposed

Project. When viewed in isolation, the near-term benefits of the Proposed Project vanish under the weight of construction work in progress (CWIP) expenses, and materialize in the long-term largely as a result of fuel and CO2 pricing assumptions.

Q. HAVE YOU ATTEMPTED TO ISOLATE THE IMPACT OF THE SECOND NGCC ON DTE'S ANALYSIS?

A. Yes. I examined the operating characteristics of Belle River and the second NGCC that replaces it in the Proposed Plan to try to tease out the impact of these assumptions. Inspecting WP KJC-344, the Proposed Plan worksheet under the 2017 Reference case assumptions, and WP KJC-323, the Shortfall Report, Belle River contributes 983 MW_{UCAP} of capacity and generates 6.83 million MWh on average between 2016 and 2028, its last full year of operation. This represents an average UCAP capacity factor of 79.3%, indicating that the unit operates not as often as a baseload resource but more frequently than a typical mid-merit plant. However, DTE only receives 81.4% of Belle River's output through its contract, resulting in roughly 5.56 million MWh on average per year.

The second NGCC unit is modeled the same as the Proposed Project. Together with the duct fire units, the plant will add 1,067 MW_{UCAP} of capacity and produce an average of 9.13 million MWh each year. The NGCC plant operates at a higher UCAP capacity factor of 97.7%, consistent with DTE's plans to operate the facilities as baseload units.

Q. WHAT IS THE NET EFFECT OF REPLACING THE BELLE RIVER FACILITY WITH A SECOND NGCC UNIT?

A. The net capacity change is quite small as the two facilities provide a similar quantity of capacity for DTE. However, because the NGCC is projected to run at a higher capacity factor, and because DTE is not entitled to the entire output of Belle River, substituting one for the other results in an increase in DTE-owned generation of roughly 3.57 million MWh per year once the second NGCC project is fully operational.

This in turn results in a substantial increase in net sales for the Proposed Plan scenario. The analysis period between 2016 and 2040 breaks down into three sections. The first, between 2016 and 2022, is characterized by the relatively constant operation of the current fleet. The second, between 2022 and 2029, captures the retirement of several coal plants and the addition of the Proposed Project. The final period, between 2030 and 2040, sees the retirement of Belle River and the commencement of a second NGCC.

Figure 33 shows the DTE-owned generation in each of these periods, along with the total load that must be met. When the generation is above the load for a year, there are net sales. When generation is below the load for a year, there are net purchases. The solid lines represent the average generation for the periods identified above, while the dotted lines show the actual year-to-year values. The impact of the second plant on the Proposed Plan scenario is clear. Net sales under the Proposed Plan increase from an average of 1.4 million MWh per year before it becomes operational to 4.4 million MWh per year after it commences. Meanwhile, net purchases under the No Build scenario increase from 7.5 million MWh to 12.9 million MWh.

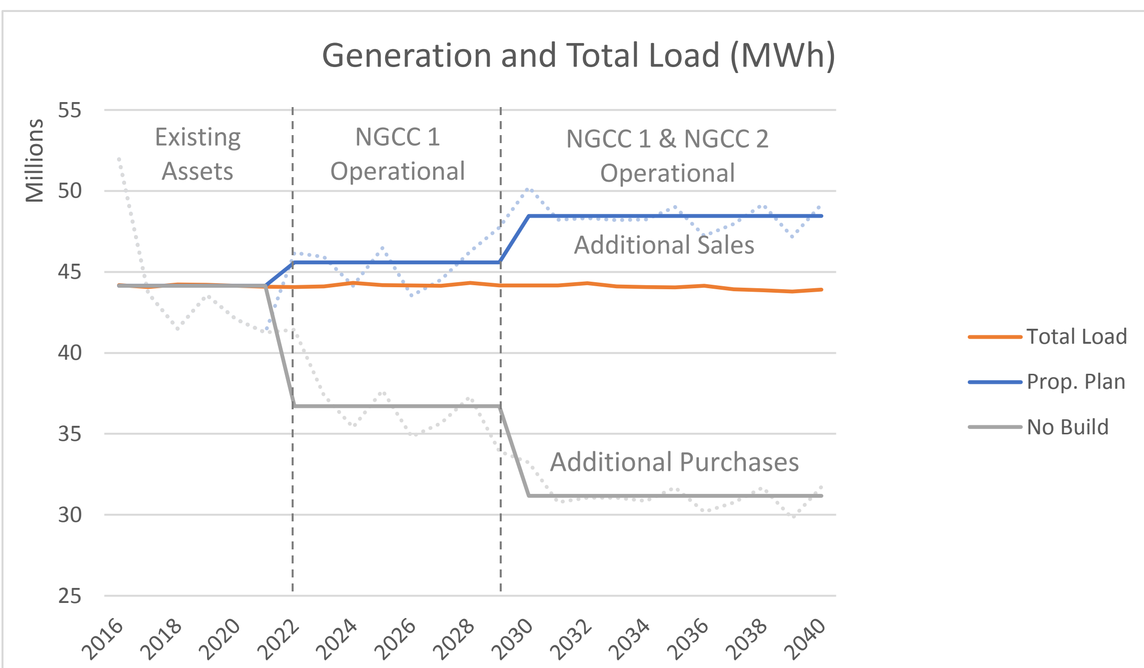


Figure 33 - Generation and Total Load

Q. DOES DTE PROVIDE MARKET PRICES FOR SALES AND PURCHASES IN THE PROPOSED PLAN AND NO BUILD SCENARIOS?

A. Yes. The worksheets contain a calculation for the all-in cost per MWh for both sales and purchases. Figure 34 below contains the projections for both scenarios for both purchases and sales. However, there are some inconsistencies that are difficult to explain.

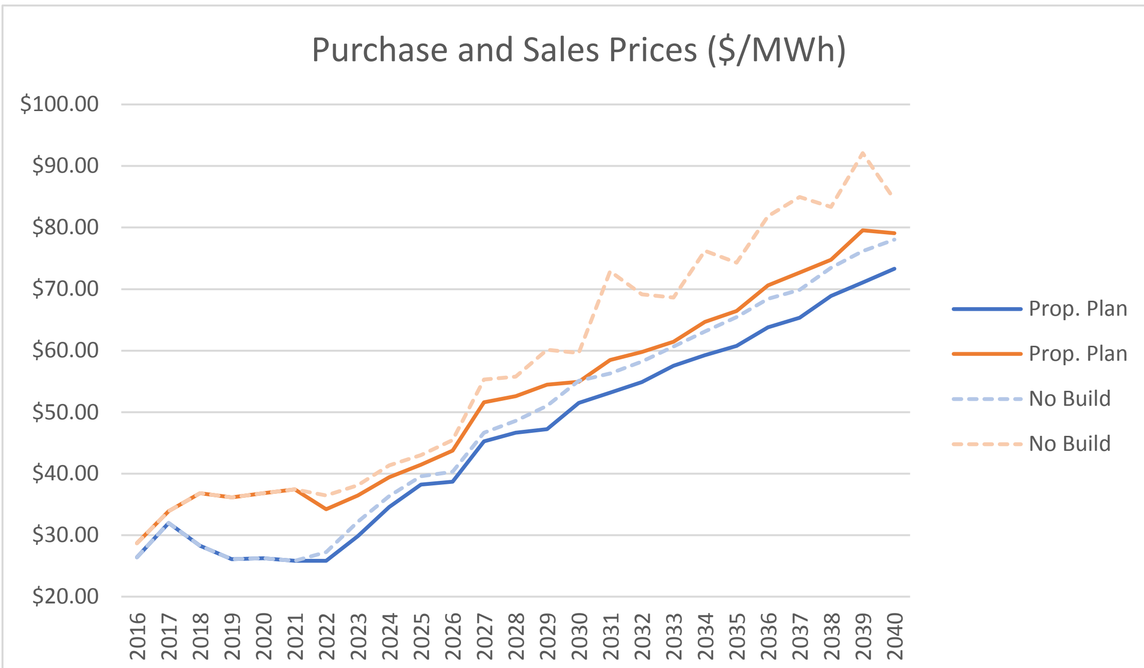


Figure 34 - Purchase and Sales Price

First, the spread between purchases and sales ranges between $8.50 and $11.50/MWh between 2018 and 2022. It is unclear what is driving this behavior, considering the spread between 2016 and 2017 were around $2/MWh. Nonetheless, the quantity of sales and purchases in this time period are the same in both scenarios, so there is no net effect.

However, starting in 2022, the two scenarios begin to diverge. Between 2022 and 2029, roughly the time when the only difference between the two scenarios is the Proposed Project, the No Build prices increase by 5-6% compared to the Proposed Plan scenario. Purchases in the No Build scenario are on average $1.95/MWh higher, while sales prices are $2.71/MWh. However, between 2030 and 2040, once the second NGCC has started operation, the price difference widens. Purchases are now $4.12/MWh, or 7%, more expensive, while sales are $9.55/MWh, or 14%, more expensive. In fact, the prices change so much that the sales price in the Proposed Plan scenario falls to almost match the purchase price in the No Build scenario.

Q. ARE THERE OTHER ASSUMPTIONS THAT OCCUR AFTER THE PROPOSED PROJECT IS INSTALLED THAT AFFECT THE REVENUE REQUIREMENT OF THE TWO SCENARIOS?

A. Yes. Carbon pricing, which is assumed to be $0/ton until 2026, ramps up from $6.70/ton in 2027 to $18.70/ton in 2040. If DTE does not have sufficient CO2 allowances in a year, it must purchase them at the then current CO2 price. If it has excess allowances, it can monetize them on the market. Additionally, the CO2 price shows up in the market price for purchased energy, as other resources must also embed the CO2 price into their costs.

The CO2 price ramp up occurs at roughly the same time as when the second NGCC unit starts operating. With this cost now embedded in energy prices, the carbon intensity of the source that DTE uses to meet load – whether from its own fleet or from market purchases – has an impact on the financials in the revenue requirement. Importantly, however, any benefit from carbon arbitrage requires there to be a carbon price in place. At best, this is currently speculative. Further, any carbon reduction impact of the second NGCC has absolutely nothing to do with the Proposed Project, despite DTE including it in the cost difference between the two scenarios.

Q. HOW DO THESE PRICE DIFFERENCES IMPACT THE REVENUE REQUIREMENT BETWEEN THE TWO SCENARIOS?

A. The second NGCC is both more efficient in converting fuel to electricity than the market average and also uses a fuel with a lower CO2 content per unit of energy. DTE assumes an average heat rate of 10,000 MMBTU/MWh for market purchases, while the NGCC has a heat rate of 6,250 (WP KJC-318, Exhibit A-4 at 223.) Based on this, for a given price of fuel, buying 1 MWh on the market will cost 60% more than generating 1 MWh from the Proposed Project.

There is a nearly 1:1 ratio of NGCC generation in the Proposed Plan scenario to the delta in net market purchases between the Proposed Plan scenario and the No Build scenario. In other words, every MWh that is produced from one of the new NGCC plants is one that is not purchased from the market. The 2016 MISO average carbon intensity was 0.59 tons/MWh, while the two NGCC have a carbon intensity of 0.376 tons/MWh when fully operational. (ELPCDE-10.1, Ex. ELP-44 (KL-44)) By taking the difference between the carbon intensity of MISO energy (used as a proxy for market purchases) and the NGCC, one can calculate what portion of the difference in operating costs between the two scenarios is due to carbon pricing. Since fuel and emissions costs are treated as operational expenses, any change in this difference falls directly to the change in revenue requirement.

Figure 35 below shows the result of this calculation. I assume that MISO CO2 intensity will fall by 1.2% annually based on the average CO2 intensity reduction between 2016 and 2050 found in the 2017 Annual Energy Outlook by the U.S. Energy Information Administration.[78] The Delta CO2 cost is calculated based on the difference between the CO2 cost from the NGCC generation (at its CO2 intensity) and the CO2 for the market purchases (at MISO's declining average CO2 intensity).

[78] AEO 2017 has a CAGR of 0.8% for net generation and -0.4% for CO2. Combined, this implies that CO2 intensity falls at a CAGR of 1.2%. Available at https://www.eia.gov/outlooks/aeo/data/browser/#/?id=62-AEO2017

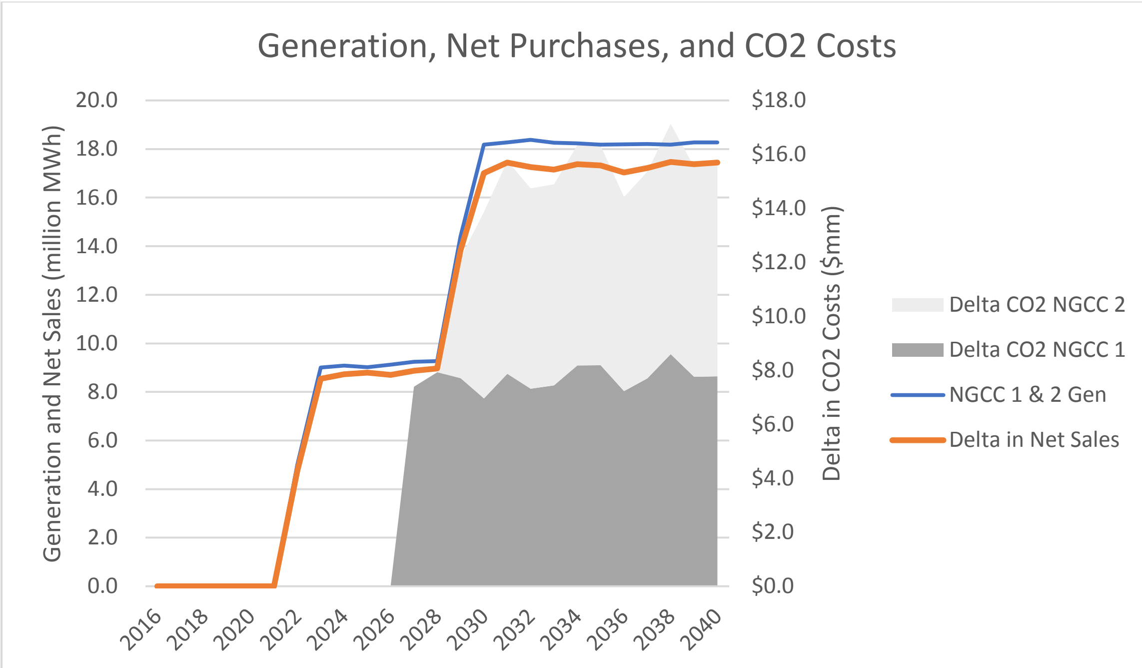


Figure 35 - Generation, Net Purchases, and CO2 Costs

There is no impact prior to 2027 as CO2 prices are assumed to be $0/ton. There is a bump in the cost differential starting in 2027, followed by a larger differential as Belle River retires and the second NGCC is fully operational. The grey area in the chart above represents the benefit of the Proposed Plan over the No Build scenario due to the CO2 differential, but 43% of the NPV of this benefit is due to the carbon reduction caused by the second NGCC plant and not the Proposed Project.

Q. HAVE YOU COMPARED THE COMBINATION OF THESE FACTORS ON THE REVENUE REQUIREMENT OF THE TWO SCENARIOS?

A. Yes. When one plots the difference in the Net Energy Costs (defined as the Fuel & Emissions cost plus the Net Energy Purchase cost) between the two scenarios, it is clear how much of the total benefit that DTE claims in the Proposed Plan comes from the second NGCC and from the CO2 arbitrage. Figure 36 below breaks down the contribution of each NGCC to the total difference between the two scenarios. The dark orange “Proposed Project – No CO2” area was created by extending the benefits accrued during the period when only that plant was operational and backing out any impact from carbon pricing. The grey "Proposed Project – CO2" area adds in the potential impact from CO2 pricing should it be implemented. The light orange value above these areas is produced by the replacement of Belle River coal generation with even more NGCC generation from the second project.

The NPV of the difference in net energy costs between the two scenarios is \$1,404 million. Of this, a full 30%, or \$414 million, comes from the second NGCC project, and an additional \$29 million comes from the potential for CO2 pricing. All told, only 68% of the net energy cost benefits of the Proposed Plan over the No Build scenario as calculated by DTE can be directly attributable to the Proposed Project.

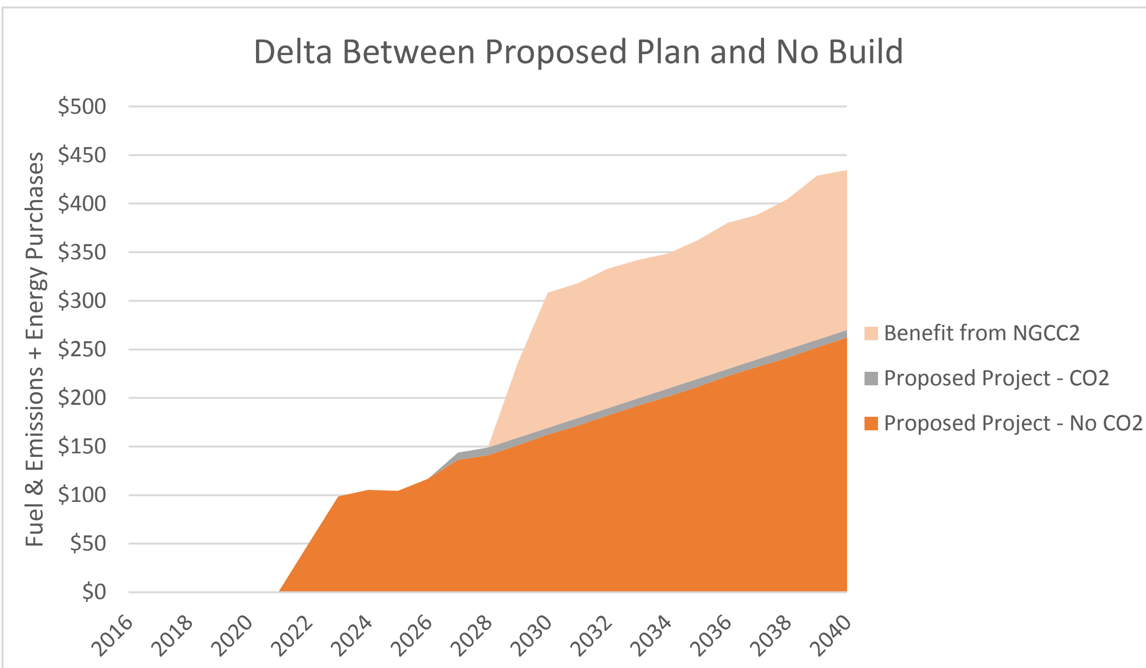


Figure 36 - Net Energy Cost Comparison

Q. WHAT IS THE FINAL RESULT OF THESE ADJUSTMENTS?

A. These three factors (capacity costs, removing the second NGCC, and fixing the heat rate error) alone – to say nothing about the myriad questionable assumptions that I have discussed previously in this testimony – shifted the result of DTE's financial comparison analysis by \$1.5 billion. Figure 37 below adds the back the cost of the second NGCC into the NPV of the Proposed Plan and adjusts the fuel cost by resetting the heat rate. This is compared to the corrected No Build – Net CONE figures. Eliminating the benefit caused by the second NGCC unit increases the cost of the Proposed Plan by the same $414 million. Fixing the heat rate adds another $423 million in cost to the Proposed Plan. Rather than a NPV benefit to customers of $663 million, the actions properly attributable to the Proposed Plan based on statutory obligations or the Proposed Project result in a NPV cost of -$858 million. And if carbon pricing does not materialize, the NPV cost will increase by an additional $29 million to -$887 million.

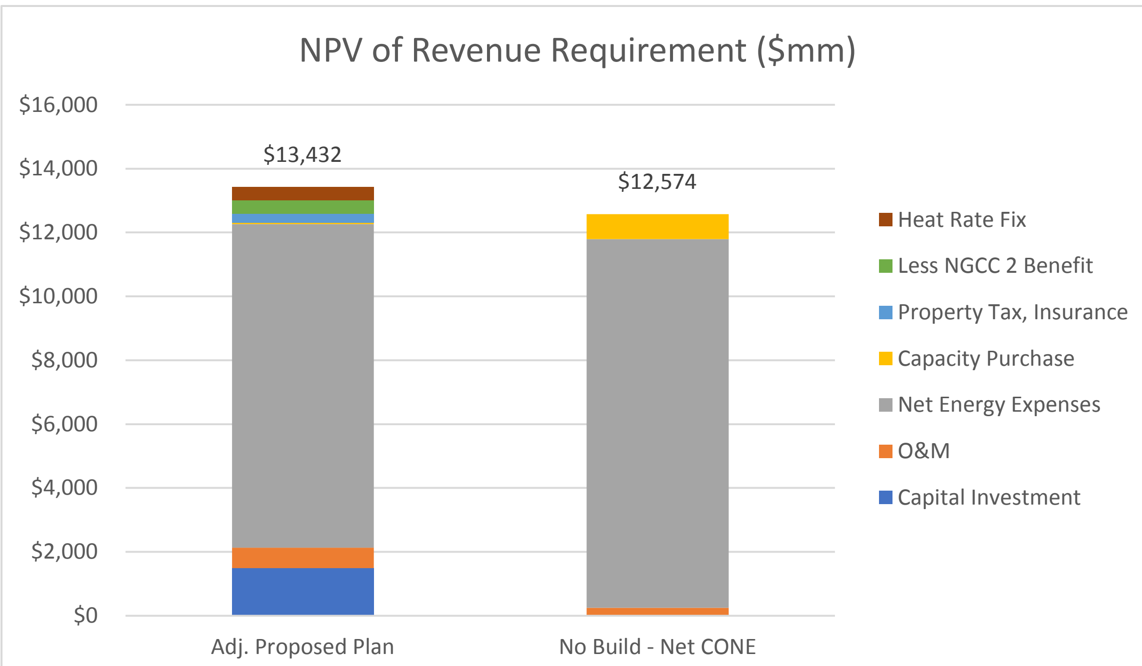


Figure 37 - Updated NPV of Revenue Requirement

DTE's own analysis show that its customers will pay a substantial amount of money before the Proposed Project is operational. This updated analysis shows that the investment is never recouped, and that customers would be better off financially if the Proposed Project and second NGCC were not constructed at all.

IV. <u>DTE'S PROPOSAL UNDERSTATES THE RISK TO ITS CUSTOMERS</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss different aspects of risk associated with the Proposed Project. I begin by discussing how the operational attributes of the Proposed Project risk becoming incompatible with the increasingly renewable generation fleet that is required to meet DTE's long-term CO2 reduction goals. From there, I compare the price of various capacity and energy resources, showing that the Proposed Project is more expensive than additional renewable energy, energy efficiency, and demand response resources and thus exposes DTE's customers to price risk. Finally, I take a deep dive into DTE's two quantitative risk analysis and demonstrate that they both have critical flaws that render their conclusions unreliable.

DTE's Proposed Plan may Build Capacity, but it is not Building the Right Capability

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. In this subsection, I discuss operational challenges that DTE may face when trying to meet its long-term CO2 goals by adding more and more "baseload" generation assets. DTE's Proposed Project is designed to meet a near-term capacity shortfall, but it risks exposing customers to an asset that will not be optimal for reaching its long-term CO2 reduction goals. I also discuss how the evolution of DTE's fleet in its 75% CO2 reduction scenario could set up substantial challenges should Fermi's operating life not be extended.

Q. DO YOU HAVE CONCERNS ABOUT HOW THE PROPOSED PLAN WILL FIT INTO DTE'S LONG-TERM PLANS?

A. Yes. DTE's Proposed Plan includes the construction of two large NGCC units. Its 75% CO2 Reduction by 2040 scenario adds a third. Adding large, inflexible resources will be increasingly out of step with DTE's future plans that will require the incorporation a large quantity of renewable generation.

Q. WHAT ARE THE OPERATING CHARACTERISTICS OF THE PLANTS THAT DTE IS RETIRING?

A. DTE plans to retire several coal-fired power plants between 2020 and 2023. Specifically, it plans to retire River Rouge, St. Clair, and Trenton Channel. (IRP Report at 10.) These plants operate in a mid-merit capacity, with anticipated capacity factors between now and their retirement roughly between 60% and 75%. In 2019, the last full year of anticipated operation of each of these units, the coal plants contribute 1,513 MW of capacity towards DTE's peak needs and generate 8,930 GWh of energy. (WP KJC-387.)

Q. PLEASE DESCRIBE DTE'S PROPOSED PROJECT AND HOW DTE INTENDS TO OPERATE THE FACILITY.

A. DTE's Proposed Project is modeled as a 1,162 MW NGCC plant with a duct firing option. It is modeled to run as a baseload generation asset, with capacity factors in the 90-92% range for the combustion turbines and 50-60% for the duct fired addition. (WP KJC-387.) To reach its full generating output, the plant is expected to take about 170 minutes from its minimum output level and 200 minutes from cold start. (ELPCDE-3.13d, Ex. ELP-45 (KL-45)) DTE also modeled a four-hour minimum run time in the IRP (ELPCDE-3.13e, Ex. ELP-46 (KL-46)) and anticipated a levelized scheduled maintenance rate of 2%, or about 175 hours per year. (ELPCE-3.13f, Ex. ELP-47 (KL-47))

While the plant can operate with one of the two combustion turbines, and can ramp its output down to a minimum output of 276 MW in the summer and 333 MW in the winter, it does not have an operating range from 0 MW to full capacity. (WP KJC-373.) Given that 2% of the hours in a year will be allocated to maintenance, and that it takes a number of hours to ramp between minimum and maximum output, the only way to attain a 90-92% annual capacity factor is to run the Proposed Project at or near its maximum power for long stretches of time. This is consistent with DTE's intention to run the plant as a "baseload" generation unit.

Q. AS MORE RENEWABLES ARE ADDED TO THE GRID, WILL DTE REQUIRE MORE "BASELOAD" GENERATION?

A. It is a common misconception that as renewables are added to the grid, utilities necessarily need to add more conventional generation as well. As utilities begin to move to higher penetrations of renewable energy, they are not seeking more baseload generation but rather seeking out more flexible generation and storage assets. One of the observations from the Joint Proposal between Pacific Gas and Electric and other stakeholders to shut down the Diablo Canyon nuclear plant in California was that the facility's baseload generation was out of step with the needs of California's increasingly renewable energy-based grid.[79] As discussed above in the 75% CO2 Reduction by 2040 sensitivity, DTE must bring in a significant amount of wind, solar, and energy efficiency resources. While demand response can make load more responsive, and geographic diversity mitigates some of intermittency of an individual renewable project, DTE's generating fleet will have to be more responsive to adjust to both variable generation and variable load.

However, DTE's long-term plan is doing just the opposite. When the generation and capacity mix of the 75% CO2 Reduction by 2040 sensitivity is analyzed by generator type, a problematic trend emerges. Essentially, DTE is replacing its mid-merit coal plants with baseload NGCC generation while adding substantial quantities of intermittent renewable generation and retaining its peaker fleet.[80] If Fermi retires before 2050, it will

[79] https://www.utilitydive.com/news/anatomy-of-a-nuke-closure-how-pge-decided-to-shutter-diablo-canyon/421979/

[80] For this analysis, the following definitions were used: Peaker: CF < 10%, Mid-merit: CF 10% - 85%, Baseload: CF > 85%.

have to be replaced with even more wind and solar for DTE to hit its 2050 CO2 reduction goals.

The decision to meet DTE's short-term capacity needs by building large-scale baseload capacity resources will limit its future choices by locking in a resource that does not provide the flexibility that will be needed in the future. As DTE adds more renewables to meet its CO2 reduction goals, the NGCCs will not be able to operate as baseload resources as discussed above. Rather than start this overbuild of inflexible assets with its Proposed Project, DTE should consider alternatives today that maintain optionality in the future.

Q. PLEASE EXPLAIN HOW DTE'S GENERATION FLEET EVOLVES UNDER THE 75% CO2 REDUCTION BY 2040 SENSITIVITY.

A. I selected several critical years to show the evolution of DTE's fleet and reproduced the results in these bar charts. 2024 is the first full year of operation after the Proposed Project and first wave of coal retirements are completed. 2031 shows the results of the second NGCC and retirement of Belle River. 2041 data was produced by holding 2040 modeled results constant while fully removing Monroe output from the mix. Finally, 2050 values were calculated to hit the 80% CO2 reduction both with and without Fermi by filling in any missing energy with a blend of 50% wind and 50% solar. Figures 39 and 39 below show the mix by generator type.

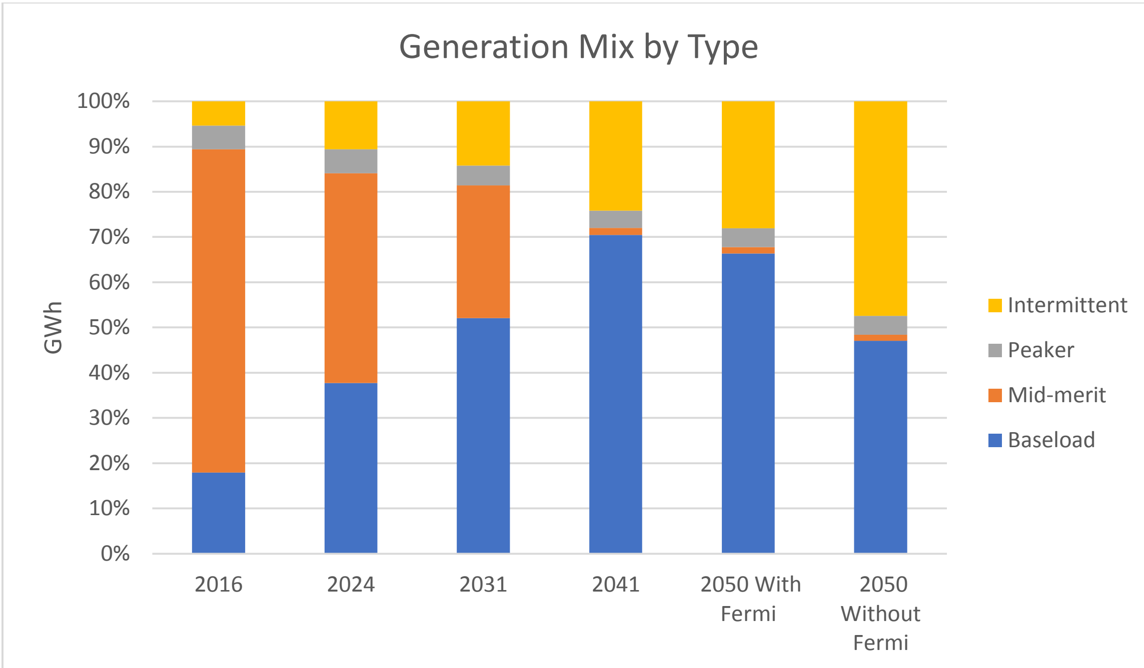


Figure 38 - Generation Mix by Type

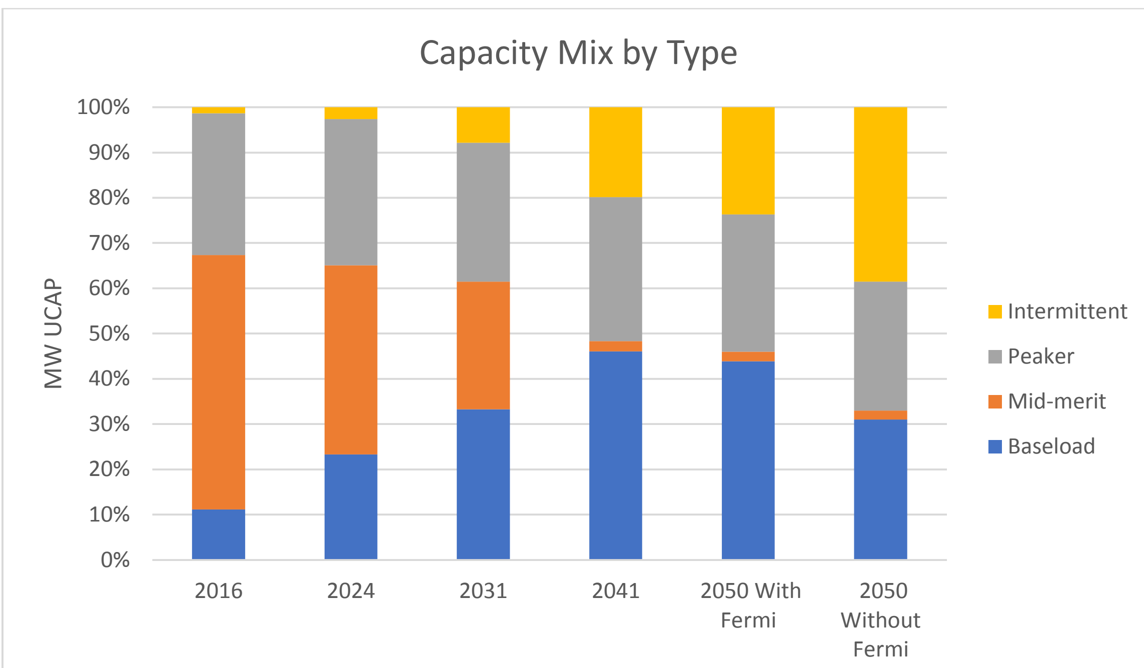


Figure 39 - Capacity Mix by Type

Q. WHAT DO THESE FIGURES SHOW ABOUT THE EVOLUTION OF DTE'S FLEET IN THIS SCENARIO?

A. As mid-merit coal capacity retires and is replaced by baseload NGCC capacity, a corresponding shift in generation appears. By 2031, baseload units are providing more than 50% of generation, and with the retirement of Monroe in 2040, this figure increases to beyond 70% in 2041. At the same time, generation from intermitted renewables grows to fill in the remainder of the gap, increasing from about 14% of generation in 2031 to nearly 25% in 2040. If Fermi is not able to extend its operating license, renewables will produce 47% of energy in 2050 to hit the CO2 reduction goals.

Q. DO YOU FORESEE ANY OPERATIONAL ISSUES WITH THE RESULTS OF THIS GENERATION MIX?

A. There are several potential issues with this mix. First, this mix incorrectly assumes that there is sufficient 24x7 load to be met by all of the baseload generating units for those units to run around the clock. To the contrary, using DTE load forecast data from WP KJC-354, it is clear from Figure 40 below that from 2031 and beyond, the amount of baseload generation exceeds the minimum monthly load from April to October.

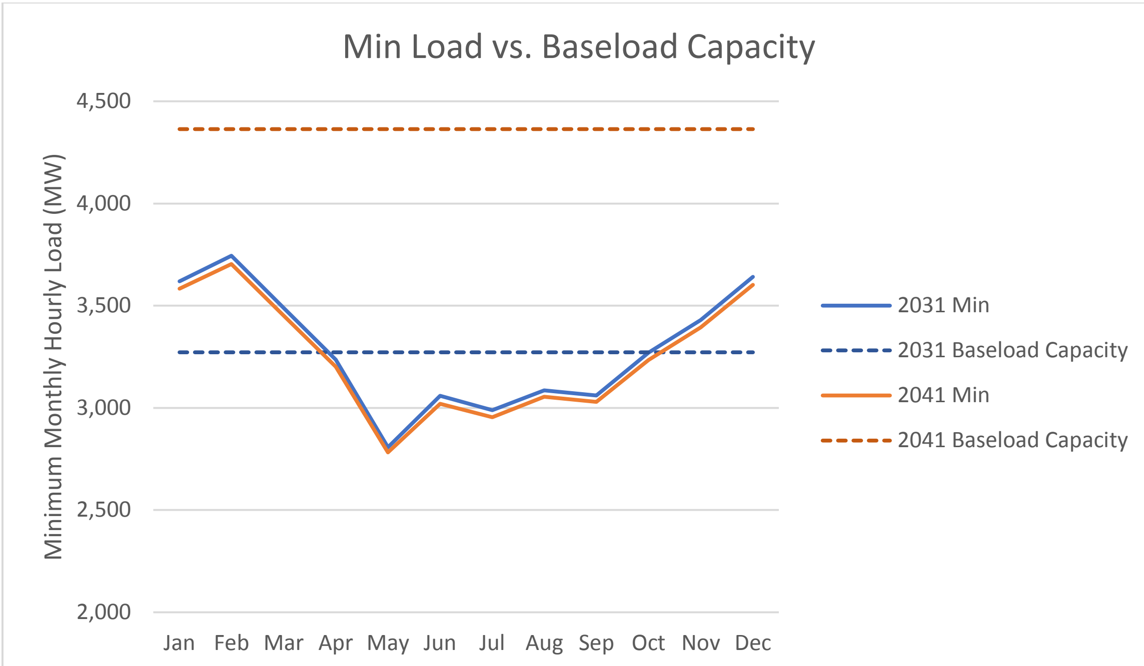


Figure 40 - Min Load vs. Baseload Capacity

While it may be possible in 2031 for DTE to ramp down the NGCC to reduce output to meet the minimum monthly hourly load levels, or potentially sell excess energy into the market, this is unlikely to be a long-term solution. By 2041, with the addition of a third NGCC unit running in baseload mode, the planned amount of baseload generation exceeds the minimum load in all months, and the gap between baseload generation levels and load exceeds 1,300 MW in many months. Given DTE's concern about transmission constraints on its system, exporting over a gigawatt of power for most of the summer could be problematic.

Second, there are issues in this mix with the balance between energy and capacity. It is clear from Figure 40 above that there is too much baseload capacity in 2041 and that it cannot all run all the time. However, if the NGCC plants shift from a constant-max-power mode to a load following mode, they will produce less energy overall, which must be made up by some other resource. Fermi is already running at maximum capacity for any month where a refueling is not taking place, and renewables are already producing zero-carbon energy based on resource availability.

Q. WHAT DTE ASSETS CAN FILL IN THIS ENERGY GAP?

A. Under DTE's assumption to limit market purchases to 300 MW, the only remaining source of generation (assuming DTE's limits on market purchases due to transmission constraints) is to run the peaking units more often. Unfortunately, the peaking units are not designed to produce significant amounts of energy. Due to their high heat rates, they are not thermally efficient. WP KJC-387 shows that some of the peakers will cost more than $300/MWh in 2031. Even the most efficient peakers top $100 MWh by 2040. Not only that, but because of their poor thermal efficiency, they will produce more carbon per MWh than the NGCC plants they are displacing. This will cause CO2 emissions to increase beyond DTE's stated goals.

Q. HAS DTE PERFORMED ANY ANALYSIS OF WHAT ITS POST-MONROE OR POST-FERMI FLEET WILL LOOK LIKE?

A. No. DTE indicated that "the years 2041 to 2050 were not modeled in the IRP modeling", and it does not appear to have fully modeled any year in which Monroe 3 and 4 are fully retired. (ELPCDE-3.2e, Ex. ELP-48 (KL-48)) DTE's response is consistent with Mr. Chreston's workpapers. The modeling window runs through 2040, but as clearly shown in WP KJC-387, Monroe units 3 and 4 remain fully operational throughout 2040. The same is true in WP KJC-374, showing the results of AURORA modeling – the coal capacity in 2039 and 2040 for MISOMECS (which corresponds to MISO Zone 7) is identical. (MECNRDCSCDE-5.7a, Ex. ELP-49 (KL-49)) If DTE has modeled a full year after the retirement of Monroe 3 and 4, it has not presented it in this case.

Not only is there no detailed modeling for DTE's system beyond 2040 that accounts for the full retirement of Monroe, there is no consideration of any sort for a post-Fermi landscape. Fermi produces almost one-fifth of DTE's energy in 2040, all of which must be replaced with zero-carbon energy to maintain the downward trajectory of CO2 emissions between 2040 and 2050. When asked about its plan, DTE responded with a fairly generic statement:

> Current plans include further curtailment of the remaining fossil fleet through retirements or lower capacity factors on gas and oil-fired units, continuing to add renewable generation, looking for emerging technologies that support lower emissions, and looking for further energy waste reduction opportunities. (ELPCDE-5.25, Ex. ELP-50 (KL-50))

DTE produced almost no generation from oil-fired units in its 2040 plan, so there is no meaningful opportunity to reduce emission from those units. Also, "looking for emerging technologies that support lower emissions" implies hoping for currently non-existing or non-commercialized technology to help close the gap. While it is certainly the case that new technologies can and likely will be developed between now and 2040, building the Proposed Project today and hoping for new innovation in the future is hardly the least risky path to pursue. And as demonstrated in its own modeling, DTE has already identified more cost-effective energy waste reduction opportunities, but decided to forgo them.

Q. WHAT IS THE RISK TO CONSUMERS IN THE LONG-TERM IF THE OPERATING CHARACTERISTICS OF THE PROPOSED PROJECT DO NOT MATCH THE NEEDS OF THE GRID IN THE FUTURE?

A. DTE has not fully analyzed how the Proposed Project fits into its long-term CO2 reduction goals. It is fairly clear that the plan currently captured in the 75% CO2 Reduction by 2040 sensitivity has serious operational problems.

DTE's current plan to build and run three NGCC is inconsistent with its 2050 goal to reduce CO2 by 80%. It has not provided any modeling to demonstrate that the Proposed Project is consistent with its long-term goals. Further, as more intermittent renewable energy is added to DTE's system, DTE will require more – not less – operational flexibility. Building a massive, centralized generation station that is run at maximum output will not create this needed flexibility.

DTE's chairman and CEO stated that an 80% reduction of CO2 by 2050 is "not only [] achievable – it is achievable in a way that keeps Michigan's power affordable and reliable." If DTE finds that its proposed project cannot be utilized as it currently intends, then DTE's customers are at risk of paying for un- or under-utilized assets. Additionally, if DTE fails in its long-term effort because it has not thoroughly vetted how the Proposed Project might fit into a broader vision to attain its CO2 reduction goals in a cost-effective and reliable manner, then DTE's customers will be harmed through either higher emissions, higher costs, or less reliability.

DTE's Proposed Plan Exposes Customers to Unnecessary Price Risk

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. In this subsection, I discuss the different price estimates for energy and capacity reduction through energy efficiency and demand response, and contrast them with DTE's estimates of producing energy and capacity from conventional generation resources. I also examine recently announced power purchase agreements (PPAs) for solar and wind generation, and demonstrate that the market has already bested by far DTE's forecast for energy prices from renewable resources.

Energy Efficiency and Demand Response are Less Expensive than the Proposed Project

Q. WHAT IS THE ESTIMATED PRICE PER KWH AND PER KW OF DTE'S ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS?

A. DTE's energy efficiency and demand response programs are extremely cost effective. While I discussed some of the concerns I have about DTE's energy efficiency assumptions above, the programs as modeled are dramatically less expense than other alternatives.

Using data from the worksheets provided as an attachment to DR MECNRDCSCDE-1.3bi, the levelized cost of capacity and energy in the 1.5% energy efficiency savings sensitivity was $63.13/kW and $0.0101/kWh. For the more aggressive

2.0% energy efficiency savings sensitivity, these costs increased slightly to $65.56/kW and $0.0105/kWh.

DTE's existing and proposed demand response programs are also very cost-effective. DTE provided data on three different programs in response to STDE-5.7. In its analysis, DTE assumed a levelized cost of $92.01/kW for the Bring Your Own Device (BYOD) program, $18.24/kW for the Interruptible Air Conditioning (IAC) program, and $60.58/kW for the Programmable Communicating Thermostat (PCT) program.

Q. HOW DO THESE COSTS COMPARE TO OTHER RESOURCES?

A. Using data from the various 2016 Reference scenario Market Valuation workpapers, DTE projects the cost of capacity and energy from a 2x1 CC Unit only at $185.88/kW and $0.0276/kWh and from a 2x1 CC Unit and Duct and $174.78/kW and $0.0305/kWh, respectively. (WP KJC-7, WP KJC-8.) Under the 2017 Reference scenario, the cost for capacity and energy from a 2x1 CC H Class is $182.12/kW and $0.0253/kWh. (WP KJC-327.) DTE did not provide a workpaper on the 2017 CC unit and duct fire option. Note that the energy costs in these worksheets did not include any carbon pricing impact.

DTE also modeled an option to build four less expensive combustion turbine peaker units. These facilities are not designed to provide as much energy as the combined cycle units, but are less expensive capacity resources. The projected costs for capacity and energy for these units are $133.86/kW and $0.0448/kWh and $133.26/kW and $0.0412/kWh for the 2016 and 2017 Reference scenarios, respectively. (WP KJC-15, WP KJC-333.)

The values for these programs are summarized below in Figure 41. The energy efficiency and demand response programs dominate the levelized cost of energy (LCOE) and levelized cost of capacity (LCOC) of the conventional units. Energy efficiency offers energy resources around 1 cent per kWh. Even the cheapest conventional resource, the 2017 2x1 CC only, is 2.5 times more expensive, and that does not include any potential carbon price impact which energy efficiency will never face.

Energy efficiency and demand response also provide capacity at a much lower cost than the conventional resources. The least expensive DR program provides capacity for a mere $18.24/kW, compared to the least expensive capacity from the 4CT of about $133/kW. Even the most expensive demand response program is still 30% cheaper than the 4CT option, and about half as costly as the NGCC options.

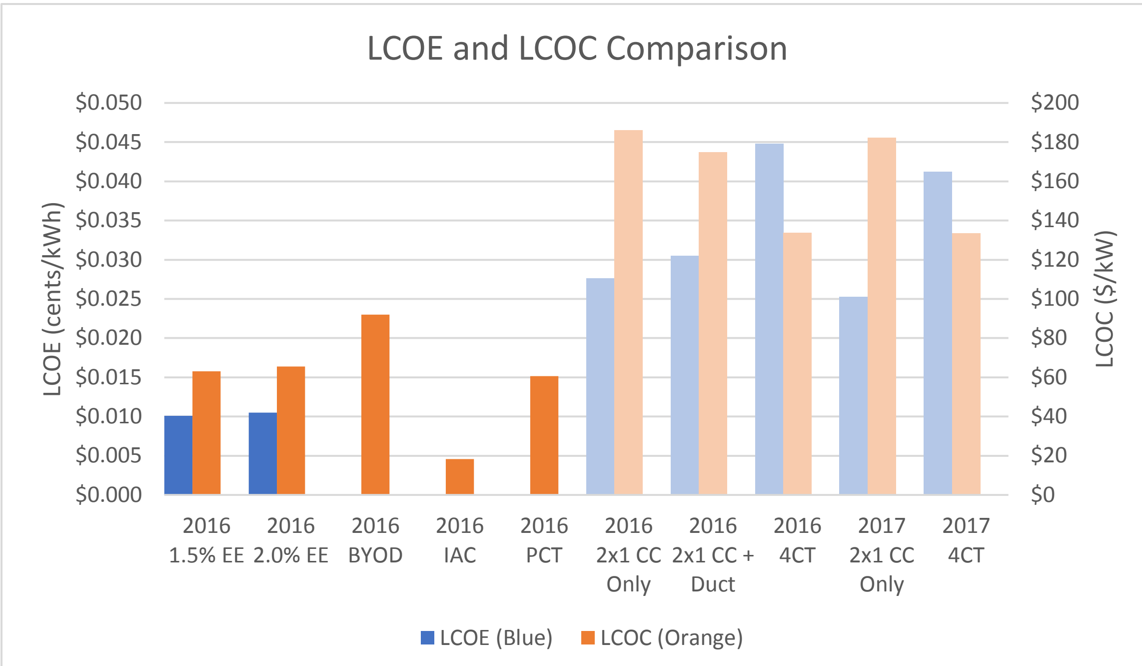


Figure 41 - LCOE and LCOC Comparison

Q. GIVEN THE COST ADVANTAGE OF THE ENERGY EFFICIENCY AND DEMAND RESPONSE PROGRAMS, IS DTE MAXIMIZING THE USE OF THESE ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES?

A. No. As discussed earlier, despite the clear cost advantage of the energy efficiency programs, DTE did not choose the 2.0% energy efficiency savings option, choosing instead the 1.5% energy efficiency savings scenario. Further, DTE assumed no BYOD or PCT programs in its 2016 and 2017 Reference scenario assumptions, nor did it include any Volt/Var Optimization and Conservation Voltage Reduction (VVO/CVR). (WP KJC-2, WP KJC-323.) While DTE is currently running a pilot program on VVO/CVR, it has indicated that it does not have enough information to determine how effective it might be. (STDE-2.6b, Ex. ELP-51 (KL-51))

DTE Overlooks Low Cost Solar and Wind PPAs

Q. ASIDE FROM FOREGOING LOWER COSTS FROM ENERGY EFFICIENCY AND DEMAND RESPONSE RESOURCES, ARE THERE OTHER LOWER-COST RESOURCES THAT DTE MIGHT BE OVERLOOKING?

A. Yes. I have discussed above my issues with DTE's renewable energy costs. It has indicated a willingness to work with third-party developers, but DTE does not appear to have modeled in any new power purchase agreements (PPAs). While it would consider renewables as part of the up-to 300 MW of annual purchases, this short-term strategy is inconsistent with the long-term nature of PPAs or PURPA offtake agreements. Given the rapid fall of solar costs, and the continued fall of wind prices coupled with new technology able to optimize output in all wind conditions, this failure on DTE's part overlooks a potential to attract lower-cost renewable energy projects.

Q. PLEASE DISCUSS SOME RECENT PPAS THAT WERE SIGNED FOR SOLAR GENERATION

A. As solar prices continue to fall, developers have been able to reduce the bid prices in recent RFPs. Two recent results show how quickly solar resources are reducing their prices. NV Energy signed two 25-MW PPAs with a levelized cost of $34.20/MWh for projects to be operational by September 2020.[81] Tucson Electric Power signed a 20-year PPA for a 100 MW solar array and a 30 MWh energy storage system that will be installed by the end of 2019. The price for the energy is "less than three cents per kilowatt hour – less than half as much as it agreed to pay under similar contracts in recent

[81] https://www.utilitydive.com/news/nv-energy-boasts-lowest-cost-ppas-for-2-proposed-solar-projects/510340/

years."[82] Xcel of Colorado just released the results of a competitive solicitation, with the median solar project bidding in at $29.50/MWh.[83]

Q. ARE MICHIGAN'S SOLAR RESOURCES EQUIVALENT TO THE STATES WHERE THOSE PPAS WERE SIGNED?

A. No, they are not. The solar resources in Nevada and Arizona are better than Michigan. However, since the levelized cost of a project is a function of its discounted energy production, one can do a rough comparison between the projects. Using NREL's System Advisor Model, I simulated a hypothetical single-axis tracking project in Las Vegas and Tucson, adjusting system costs until the model produced an LCOE of $34.20/MWh and $29.99/MWh, respectively. All other modeling parameters were left at their default values.

I then used these same system costs to simulate a project in Michigan. The Tucson cost parameters produced an LCOE of $44.30/MWh, while the Las Vegas project produced an LCOE $51.20/MWh. While a more detailed analysis would be needed to anticipate how developers might respond to an RFP in DTE's territory, the prices above provide a good data point on how competitive solar pricing has become. Further, these prices represent both the energy and capacity benefits of a project in a single cost per MWh. When some of the value is appropriately applied to capacity, the resulting energy costs would be even lower.

Q. DO YOU HAVE AN EXAMPLE OF SOLAR PPA PRICING FROM MICHIGAN?

A. Yes. The Lansing Board of Water and Light approved a PPA for 20 MW of solar in March 2015, over two-and-a-half years ago. While solar prices have fallen since then, the prices were lower than DTE's LCOE estimates above for 2018 projects. Reports at

[82] https://www.tep.com/news/tep-to-power-21000-homes-with-new-solar-array-for-historically-low-price/
[83] https://www.utilitydive.com/news/xcel-solicitation-returns-incredible-renewable-energy-storage-bids/514287/

the time indicate that the PPA price was "roughly $60/MWh."[84] Not only that, but PPA prices are locked in for the duration of the contract, and do not expose DTE's customers to fuel price risk.

Q. PLEASE DISCUSS SOME RECENT TRENDS IN WIND GENERATION.

A. As with solar, wind generation has seen a steady decline in pricing and improvement in technology. The use of higher hub heights and larger rotors has resulted in an increase in the power output per turbine. Further, turbines that are specifically designed for lower-speed wind sites are gaining in market share. The combination of these factors enables wind developers to economical site projects where they had not been previously able to.[85]

The U.S Department of Energy's 2016 Wind Technologies Market Report tracks signed PPAs that include both energy and RECs. In its latest version, the average 2015 Great Lakes region PPA was signed at a levelized cost of $36.01/MWh (including the RECs).[86] Further, many of these PPAs are signed with no escalators, meaning they actual *decrease* in price in real terms over the life of the contract. And as with any PPA, the price is locked in for a long period of time.

Q. WHILE WIND POWER IS ALREADY COMPETITIVE TODAY, IS THE INDUSTRY PUSHING TO REDUCE COSTS EVEN FURTHER?

A. Yes. A recent report from the National Renewable Energy Laboratory details efforts that the industry is taking to drive the wind industry forward. By focusing on a holistic approach to optimize facility operations, NREL lays out strategies that will enable wind power plants to "be designed and operated to achieve enhanced power production, more efficient material use, lower operation and maintenance and servicing costs, lower risks

[84] http://midwestenergynews.com/2015/03/11/planned-project-would-nearly-double-michigans-solar-capacity/
[85] *2016 Wind Technologies Market Report*, U.S. Department of Energy. Available at https://energy.gov/eere/wind/downloads/2016-wind-technologies-market-report
[86] Id, 2016_WTMR_Data_File-081417.xls

for investors, extended plant life, and an array of grid control and reliability features."[87] The goal of these actions is to drive the average *unsubsidized* LCOE of wind energy to $23/MWh (in $2015) by 2030, "a reduction of 50% or more from current cost levels."[88]

Q. HOW DO THESE PRICES COMPARE TO DTE'S ESTIMATES FOR ITS PROPOSED PROJECT?

A. They compare well, even at today's prices. If one divides the NPV of total costs of the CC 2x1 H Unit with Duct Fire by the NPV of generated energy, the LCOE of the facility is $59.22/MWh. (WP KJC-7.) When updated 2017 assumptions are used for the 2x1 CC H Class unit, the cost falls somewhat to $51.72/MWh. (WP KJC-327.) DTE also models the LCOE of 2x1 H Class CC unit in its LCOE worksheet. (WP KJC-479.) Under the assumptions in this file, the LCOE of the project is $65.13/MWh. Further, DTE's LCOE calculator does not include any carbon price.

Of course, the solar projects and the NGCC project have different operating characteristics, with the solar project providing less capacity than the NGCC. However, solar facilities have zero fuel price risk, and with a signed PPA, future prices are guaranteed. This guarantee provides value to DTE's customers compared to taking price risk on future fuel fluctuations.

When comparing wind prices, I decided to contrast wind PPAs against the dispatch cost for the Proposed Project. While this discards the 12.6% capacity credit that wind earns, it highlights the increasing cost of energy from the Proposed Project driven by escalating natural gas prices. I compare the 2015 PPA value, which includes RECs as well as energy, and also the 2030 NREL pathway, converted to nominal levelized cost. Both of these values overstate the cost of wind energy; the 2015 value includes RECs and

[87] *Enabling the SMART Wind Power Plant of the Future Through Science-Based Innovation*, National Renewable Energy Laboratory at iv. Available at https://www.nrel.gov/docs/fy17osti/68123.pdf
[88] Id.

discounts capacity, and the 2030 value further discounts capacity and grid services. Even with these conservative estimates, the benefit of wind power for producing energy is clearly shown in Figure 42 below.

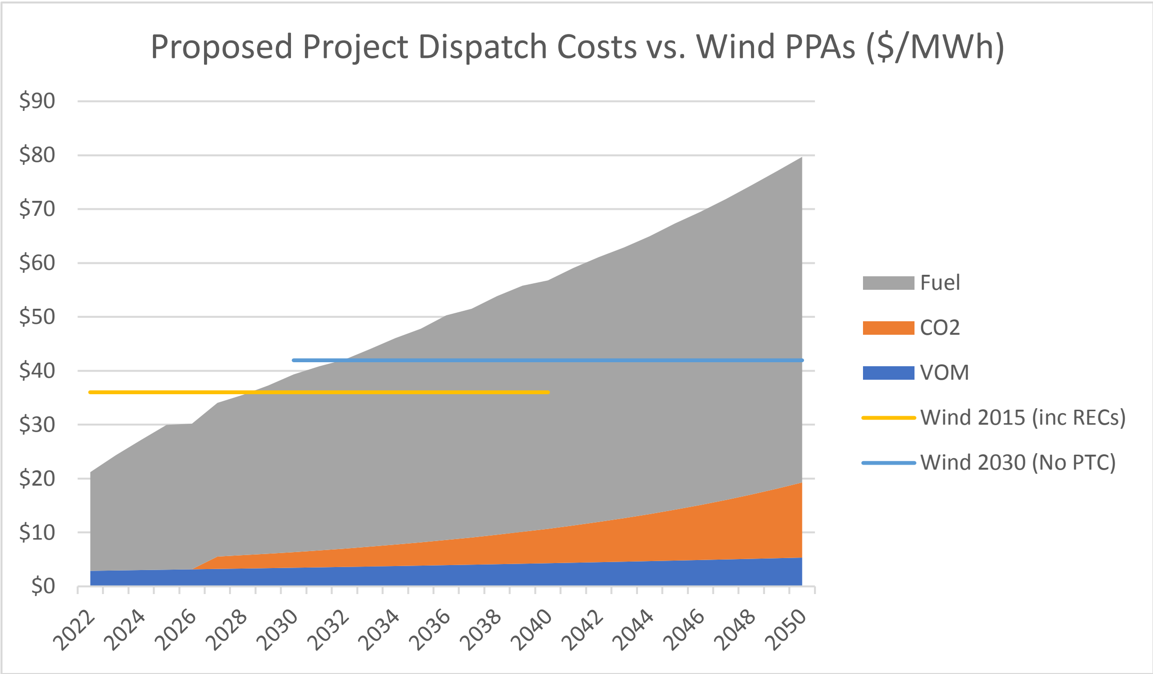


Figure 42 - Proposed Project Dispatch Costs vs. Wind PPAs

Even with 2015 pricing, a wind project is quickly "in the money" when compared to the projected costs of producing energy from the Proposed Project. The 2030 project performs even better, with flat costs that end up nearly half of the cost of running the Proposed Project by 2050. The benefits to customers of locking in a guaranteed, long-term rate that is not dependent on natural gas prices is obvious. Meanwhile, roughly 44% and 55% of all Proposed Project costs in the market valuation worksheets and LCOE calculator, respectively, are fuel costs which are directly exposed to natural gas price volatility.

Q. DESPITE THE COST ADVANTAGES OF ENERGY EFFICIENCY, DEMAND RESPONSE, AND MARKET-BASED PPAS, DTE CONTINUES TO RECOMMEND BUILDING A LARGE, CENTRALIZED NGCC THAT IS EXPOSED TO NATURAL GAS PRICES FOR DECADES. DOES DTE PROVIDE ANY REASON FOR THIS POSITION?

A. As I discussed above, DTE simply believes that a portfolio of distributed resources such as energy efficiency, demand response, and renewable energy "cannot meet the intended purpose of the Proposed Project." (ELPCDE-7.4f, Ex. ELP-4 (KL-4)) Given that its definition of the purposed of the Proposed Project is itself flawed, it is no wonder that DTE did not adequately consider other available resources to meet its obligations to serve its customers.

V. DTE'S RISK ANALYSES ARE FLAWED AND SHOULD NOT BE RELIED UPON

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A. In this section, I dive into DTE's two quantitative risk analyses. These analyses are supposed to represent a check on the modeling results, and DTE purports their results to support its Proposed Plan. However, as I step through the two analyses and point out methodological flaws, it become clear that the risk analyses should offer no solace to DTE's customers. The analytic hierarchy process (AHP) analysis falters in its final and most critical step, producing semi-random results that cannot be relied upon. The Stochastic analysis, while not suffering from the same random-result problem, produces results that are at best not representative of the overall value of the project and more likely reflect a reality that has almost no chance of actually occurring.

Summary of Concerns Regarding DTE's Risk Analyses

Q. PLEASE DESCRIBE THE FOUR RISK ANALYSES THAT DTE PERFORMED.

A. DTE performed two quantitative risk analyses and two more qualitative risk analyses. The two quantitative analyses were an analytic hierarchy process (AHP) and a stochastic analysis. The two more qualitative analyses included the development of an updated 2017 Reference scenario and a "change analysis." These analyses are discussed in section 12 of the IRP Report.

The AHP analysis is a method that attempts to compare outcomes of different scenarios by developing a set of criteria that are measured against each other to determine which outcome is more likely to occur and which outcome is preferable. DTE created five different criteria (cost, environmental, portfolio balance, commodity prices, and market risk) that are difficult to compare directly against each other. Using scores from subject matter experts and a sequence of statistical analyses, the AHP attempts to quantify subjective preferences on these five categories into a final score for the portfolio.

The stochastic analysis uses probability distributions for key inputs such as natural gas prices and load forecasts. A scenario is developed using a random set of input values, and the combination is run through the AURORA model to develop an expected cost of the portfolio. DTE then compares the expected cost against the "economic risk" (defined as the average of the 10% highest cost scenarios) of the portfolio.

The 2017 Reference scenario used refreshed data for most of the major assumptions. The scenario was rerun through the various models and the results were compared against the 2016 Reference scenario. The concerns I have with the 2017 Reference scenario were discussed in detail above.

Finally, a "change" analysis evaluated different sensitivities that did not select a 2x1 CC in 2022 and determined what steps could be taken to conform them to a choice of building a 2x1 CC in 2022. Generally, the analysis showed that in high load scenarios, additional resources could be added later, and in low load scenarios, the 2x1 CC could be delayed.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE AHP ANALYSIS.

A. The AHP analysis attempts to convert subjective opinions into quantitative values that can be analyzed in more detail. From a process perspective, my biggest concern is that DTE did not utilize any outside resources when scoring the different criteria (e.g. cost, environmental, etc.) against each other. Although as a utility DTE might be primarily focused on cost and market risk, it is possible that DTE's consumers might value environmental factors, and might consider access to more market-facing purchases as a benefit rather than a problem.

From a methodological standpoint, I identify two major problems with DTE's analysis. The first involves how DTE constructs the alternative portfolios to model. DTE adds a massive amount of combustion turbine capacity along with the solar, wind, and DR resources. Although DTE claims this was done to compare options on an equivalent capacity basis, as discussed earlier, it is a result of DTE's category error when assessing the ability of distributed resources to meets its resource adequacy obligations. Consistent with the deficiencies I identify earlier in my testimony, DTE also fails to consider more solar and wind resources earlier in the analysis window, forgoing federal tax benefits. Nor does DTE utilize more aggressive energy efficiency resources, despite their value to consumers. DTE's choices result in forcing the answer on the model, rather than allowing the model to fully consider a properly constructed alternative scenario.

The second, and more problematic issue, is that the final step in DTE's AHP relies on a fatally flawed calculation that is based on results of a single value from a single modeling run. Further, the method does not vary based on scale – saving $1 can be as useful a result as saving $100 million. Taken together, this critical step produces more or less random results when tested against real-world variations in input prices. This flaw renders moot DTE's conclusion that the AHP analysis strongly supports its Proposed Project, and prevents stakeholders from drawing any conclusions at all from its AHP analysis.

Q. PLEASE SUMMARIZE YOUR CONCERNS WITH THE STOCHASTIC RISK ANALYSIS.

A. While I have fewer concerns with the stochastic risk analysis than with the AHP analysis, DTE's discussion of the results dramatically overstates the relevance of the analysis. DTE fails to provide important context on both the scope of the analysis, which is focused only on total cost under the Reference scenario, and the actual chances of the high-cost outcomes of occurring. In the end, the stochastic analysis presents information relevant to only 11.7% of the total scope of the AHP analysis, and fails to mention that the odds of the high-cost outcomes it discusses are on the order of 220,000 to 1.

AHP Analysis Methodology Overview

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. In this subsection, I provide in some detail a step-by-step method that fills in the many gaps in DTE's explanation about this tool. I introduce some of the concepts, such as Q Value, that I later critique. I hope that by providing this background, stakeholders will be able to better understand why I cannot recommend that its results be relied upon.

Q. HOW DOES DTE DESRCRIBE THE FUNCTION AND OBJECTIVE OF THE AHP ANALYSIS?

A. It describes the AHP analysis as "a process that decomposes complex problems into a hierarchy of criteria and alternatives. Both qualitative and quantitative criteria can be compared using informed judgements to derive weights and priorities." DTE's objective with the AHP analysis was to "select an IRP resource plan." (IRP Report at 210.)

Q. DID DTE PROVIDE SUFFICIENT INFORMATION IN ITS IRP REPORT FOR A READER TO UNDERSTAND THE INTRICACIES OF THE AHP METHODOLOGY?

A. In my opinion, no. While I understand that DTE was trying to balance the level of detail in its IRP Report, the AHP analysis is one of the two quantitative analyses that it relies on to support the Proposed Project and the information provided in the report and appendices is insufficient to understand how the analysis works and what the impact of each step in the process is.

As an example, this is how DTE described calculating the local weights from each portfolio run: "The metrics across the different plans were normalized on a logistic scale across the different portfolios. These were then given a local weighting that added up to 1.00 under each criterion." And this is how DTE described how to combine the calculations in the AHP methodology: "The results of the pairwise comparisons of the scenario likelihoods and the criteria ratings were computed using eigenvectors and applied across the portfolio rankings using a computational tree." (IRP Report at 214-215.)

DTE provides a detailed memo in Appendix Q of Exhibit A-5 from PACE Global on how its stochastic analysis was performed, but no corresponding document was provided for the AHP analysis. Although DTE did explain some of its choices in the IRP Report narrative, other values were only found in the workpapers. And some of the values in the workpapers needed further explanation through data requests.

Q. CAN YOU PROVIDE A MORE USER-FRIENDLY OVERVIEW OF THE AHP ANALYSIS?

A. Yes. The AHP analysis is complex tool that might not be familiar to many stakeholders. At its core, the AHP analysis is a method that seeks to compare characteristics against each other that might not lend themselves to consistent metrics. For instance, one might want to compare a car based on its safety, performance, reliability, cost, and appeal. One cannot simply use the same metrics to compare safety with performance. Likewise, while reliability might impact cost, there are expensive cars that are unreliable and inexpensive cars that are reliable. Further, some customers might value appeal more than anything else, while cost could be the critical factor for other customers.

The AHP analysis attempts to combine all of these disparate elements into one common rank that represents the weighted average of each car based on the relative importance of each characteristic and the individual score of each metric. In DTE's application, it seeks to identify the best IRP plan from a list of four alternatives based on criteria such as cost, environmental, portfolio balance, commodity prices, and market risk.

Q. PLEASE DESCRIBE THE FOUR ALTERNATIVE PORFOLIOS THAT WERE ANALYZED IN THE AHP ANALYSIS.

A. DTE chose to analyze four scenarios and three sensitivities in its AHP analysis. It used the 2016 Reference scenario as one of the portfolios, and selected alternative portfolios comprised of wind, solar, and demand response along with additional combustion turbine (CT) resources. (IRP Report at 214.). These portfolios were modeled in Strategist using a combination of input assumptions. In its IRP report, DTE explains its portfolio choices as follows:

> The four alternative resource plans evaluated were significantly different from each other. DTEE selected plans from the Strategist modeling results that included large blocks of wind, solar, and demand response as shown in Table 12.1.1-6. To make the resource plans equivalent on a capacity basis, a block of CT units is required to firm up the non-dispatchable resources. The potential size and availability of the demand response programs is much lower than the 1,100 MW CCGT in the base resource plan that it would be replacing. A demand response program of feasible size was used in combination with the CT block. (IRP Report at 214.)

Q. PLEASE DESCRIBE WHAT SCENARIOS AND SENSITIVIES THAT DTE USED IN ITS AHP ANALYSIS.

A. DTE did not rerun these alternative portfolios through all of its IRP scenario and sensitivity combinations. Rather, they were modeled in a number of different combinations, with at least one run for each of the five main scenarios. The combination of scenarios and sensitivities that were modeled for each portfolio is shown below in Table 5. (WP KJC-317.)

Scenario	Sensitivity
2016 Reference Case	
2016 Reference Case	Base Load / High Capital Cost
2016 Reference Case	High Load
2016 Reference Case	Low Load
High Gas Price	
Low Gas Price	
Emerging Technology	
Aggressive CO2	

Table 5 - AHP Scenarios and Sensitivities

Q. PLEASE DESCRIBE THE STEPS TAKEN TO DEFINE AND CALCULATE THE RELATIVE WEIGHTS OF EACH IRP CRITERIA, SCENARIO, AND SENSITIVITY IN THE AHP ANALYSIS.

A. The AHP analysis utilizes a combination of subjective ratings from subject matter experts (SME) and statistical techniques to determine the relative rankings of alternative IRP resource plans when measured against a number of different scenarios and sensitivities.

The process begins by defining the criteria that are most important when evaluating the outcome of different IRP resource plans. DTE selected five criteria: cost, environmental, portfolio balance, commodity prices, and market risk. These criteria were matched with metrics that were available through the Strategist model to measure the criteria results. For instance, the "cost" criteria was measured by the PVRR output of the model. The complete mapping of criteria to metrics is listed below in Table 6. (IRP Report at 210.)

AHP Criteria	Metric
Cost	PVRR
Environmental	CO2 Tons
Portfolio Balance	Function of the amount of base load to peaking units added
Commodity Prices	Weighted average of the Fuel volatility index for gas, coal, nuclear, oil, and renewable
Market Risk	Net purchases and sales

Table 6 - AHP Criteria and Metrics

After these criteria are defined, the next step is to develop pairwise weightings to compare each individual criterion against each other. The rating scale used in the AHP pairwise comparison uses qualitative language to convert subjective judgements into quantitative values that can be used for analysis shown in Table 7 below.

Intensity of Importance	Definition	Explanation
9	Extreme Importance	The evidence favoring Criteria 1 over Criteria 2 is of the highest possible order of affirmation
7	Very Strong Importance	Criteria 1 is strongly favored over Criteria 2; its dominance is demonstrated in practice
5	Strong Importance	Experience and judgement strongly favor Criteria 1 over Criteria 2
3	Moderate Importance	Experience and judgement slightly favor Criteria 1 over Criteria 2
1	Equal Importance	The two criteria contribute equally to the objective

Table 7 - AHP Scoring Definitions

A pairwise comparison value of 7 means that the first event has “odds” of 7:1, that is, it is 7 times more likely to occur or 7 times more important than the second. This means that the first event will occur 87.5% of the time (7/8), while the second event will occur 12.5% of the time (1/8). The rating scale is symmetric around 1, so the corresponding value of 5 (Criteria 1 strongly over Criteria 2) is its reciprocal of 0.2 (Criteria 2 strongly over Criteria 1). Intermediate values (i.e. 2, 4, 6, and 8) can also be used to indicate importance between the qualitative definitions above.

DTE gathered input from various members of its team to calculate the relative importance of each of the criteria. (ELPCDE-5.7, Ex. ELP-52 (KL-52)) These individual data points were combined to create an average for the group for each pairwise comparison. For example, when comparing Cost to Environmental, the geometric average of the five scores of 3, 5, 4, 3, and 7 resulted in an aggregate preference of 4.17. (WP KJC-317.) For this specific metric, DTE determined that cost was between "moderately" and "strongly" more important that environmental results for a given IRP plan. The resulting matrix of SME opinions is below in Table 8. Values greater that 3 (or less than 1/3), indicating more than a "moderate" preference, are highlighted.

	Cost	**Environmental (CO2)**	**Portfolio Balance**	**Commodity Price Risk**	**Market Risk**
Cost	1	4.17	5.07	2.45	1.48
Environmental (CO2)	0.24	1	2.35	1.38	0.63
Portfolio Balance	0.20	0.43	1	0.54	0.26
Commodity Price Risk	0.41	0.73	1.87	1	0.43
Market Risk	0.67	1.59	3.77	2.30	1

Table 8 - AHP Criteria SME Pairwise Comparison

These values were then used to calculate the relative priority for each criteria using linear algebra techniques. (WP KJC-317.) The results of this step show the importance of criteria in the form of normalized weights that can be applied to a given portfolio. These values are shown below in Table 9.

Criteria	**Local Weight**
Cost	40.4%
Environmental (CO2)	14.5%
Portfolio Balance	6.8%
Commodity Price Risk	12.5%
Market Risk	25.8%
Total	**100.0%**

Table 9 - Criteria Relative Importance

At the end of this process, DTE has calculated a method to "score" IRP Plans against each other. This scoring system creates a weighted average value for each Plan, with the weights represented above. The Cost criteria is by far the most important, representing more than two-fifths of the total score of a portfolio. The Market Risk category (net purchases and sales of a given modeling run) is second, with just over a quarter of the weight. Environmental and Commodity Price Risk (fuel price volatility) represent about one-seventh and one-eighth of the final result, respectively, with Portfolio Balance (peak and baseload generation assets), the lowest weight at roughly 1/14 of the aggregate. The results of the top two criteria (Cost and Market Risk) determine about two-thirds of final value for a portfolio.

DTE follows a similar methodology to create weights for its major IRP scenarios. These values are summarized in Tables 10 and 11 below, in this instance representing the likelihood of occurrence rather than the preference.

	Reference Case	**High Gas Price**	**Low Gas Price**	**Emerging Technology**	**Aggressive CO_2**
Reference Case	1	6.90	3.06	2.93	3.50
High Gas Price	0.14	1	0.20	0.30	0.38
Low Gas Price	0.33	4.95	1	1.62	1.90
Emerging Technology	0.34	3.36	0.62	1	1.86
Aggressive CO_2	0.29	2.60	0.53	0.54	1

Table 10 - IRP Scenario SME Pairwise Comparison

Scenario	**Local Weight**
Reference Case	46.0%
High Gas Price	5.0%
Low Gas Price	21.5%
Emerging Technology	16.3%
Aggressive CO_2	11.3%
Total	**100.0%**

Table 11 - Scenario Relative Importance

According to DTE's SMEs, the Reference scenario (in this case, the 2016 Reference scenario) is by far the most likely outcome, with the Low Gas Price scenario second. As with the Criteria calculations, the top two scenarios determine about two-thirds of the weight for a given IRP plan.

Similar calculations were done for load sensitivities (SMEs estimating a 72% chance of Base Load, 23% chance of Low Load, and 5% chance of High Load) and capital costs (88% chance of Base Capital Costs and 12% chance of High Capital Costs).

Q. ONCE THESE VALUES WERE CALCULATED, WHAT WAS THE NEXT STEP IN THE AHP ANALYSIS?

A. The relative importance and likelihood ratings calculated from the SME inputs need to be combined to determine aggregated weights that will be applied to individual portfolio results. Using a decision tree methodology, DTE calculated the final weight that would be used for each criteria in each portfolio. These weights are reflective of both the likelihood of the scenario/sensitivity combination occurring as well as the preferences between each criteria. Data from WP KJC-317 is reproduced below in Table 12. For simplicity sake, the final step of multiplying by the Criteria weights is shown only for the first entry highlighted below (Reference Case, High Load). In the full analysis, each combination of scenarios and sensitivities would be multiplied by the corresponding criteria value to determine the final weights.

Scenario	Local Weight	Sensitivity	Local Weight	Sensitivity	Local Weight	Criteria	Local Weight	Final Weight
Reference Case	46.0%	High Load	5.1%			Cost	40.4%	0.9%
						Environmental (CO2)	14.5%	0.3%
						Portfolio Balance	6.8%	0.2%
						Commodity Price Risk	12.5%	0.3%
						Energy Risk	25.8%	0.6%
		Low Load	22.7%					10.4%
		Base Load	72.2%	High Cap Costs	12.5%			4.1%
				Base Cap Costs	87.5%			29.0%
High Gas Price	5.0%							5.0%
Low Gas Price	21.5%							21.5%
Emerging Technology	16.3%							16.3%
Aggressive CO_2	11.3%							11.3%
Total	**100.0%**		**100.0%**		**100.0%**		**100.0%**	**100.0%**

Table 12 - AHP Local Weights

The Final Weight in this table is the product of each hierarchy level and represents the share of the final score that is derived from the results in each case. For instance, while the Reference Case Scenario (Reference Case, Base Load, Base Cap Costs) has the highest local weight in each of the three levels of analysis, due to the choice of sensitivities, this case only represents 29% of the final score.

Q. PLEASE DESCRIBE THE PROCESS TO CALCULATE THE RESULTS OF THE PORTFOLIO ANALYSIS TO WHICH THESE WEIGHTS ARE APPLIED.

A. After the weights of each branch of the AHP decision tree are calculated, they are applied to the result of the portfolio analysis. This calculation is quite different from the previous steps as it is derived from the quantitative outputs of the Strategist model run. While the first step in the process involves converting SME opinions to quantitative preferences and probabilities, the second step compares the values of different key metrics such as PVRR and CO2 emissions from each scenario to calculate a "weight" based on the distribution of those outcomes.

As discussed above, each criteria from the AHP analysis is represented by a corresponding metric that is exported from the modeling runs. To compare different IRP plans, DTE first gathers the data for each metric (PVRR, % Peakers, CO2 emissions, Fuel Volatility, Net Sales) for each of the four main IRP plans it analyzed. All values are directly compared except for Fuel Volatility, which is further processed to incorporate price volatility by fuel type into the modeled fuel mix.

Each of these values is compared across portfolios. A minimum and maximum value is calculated, and each point is assigned a "Q value" based on its relative position between the minimum and maximum value using a logistic distribution function and assuming that the maximum value is 5 times better than the minimum value. From these Q values, the final local weight of each metric is calculated. These steps are shown below in Table 13 for the example calculation from WP KJC-318, which compares the cost (NPVV) of the Baseline scenario.[89]

Alternative	Total Cost	Residual Cost	Interval level Score	Q Value	Local Weight
CC	15,768,015	-	1.000	5.000	0.504
CT + Wind	16,237,132	469,117	0.000	1.000	0.101
CT + Solar	16,167,743	399,728	0.148	1.269	0.128
CT + DR	15,952,727	184,712	0.606	2.653	0.267

Table 13 - Portfolio Local Weight Calculation

These steps are repeated for each scenario/sensitivity that was included in the AHP analysis. The values for the Reference scenario are duplicated below in Figure 43 using data from WP KJC-318 with the column headers aligned with the metrics above.

[89] Residual Cost is the incremental cost above the minimum value for this metric. The Internal Level Score is the normalized relative position between the minimum and maximum value of the data point. The Q Value is calculated as Q^Interval Level Score, with Q=5. This results in the "best" value getting a Q Value of 5 and the "worst" value getting a Q Value of 1. Finally, the local weight is the Q Value of a particular portfolio divided by the sum of the Q Values for all portfolios. See WP KJC-318 for more details.

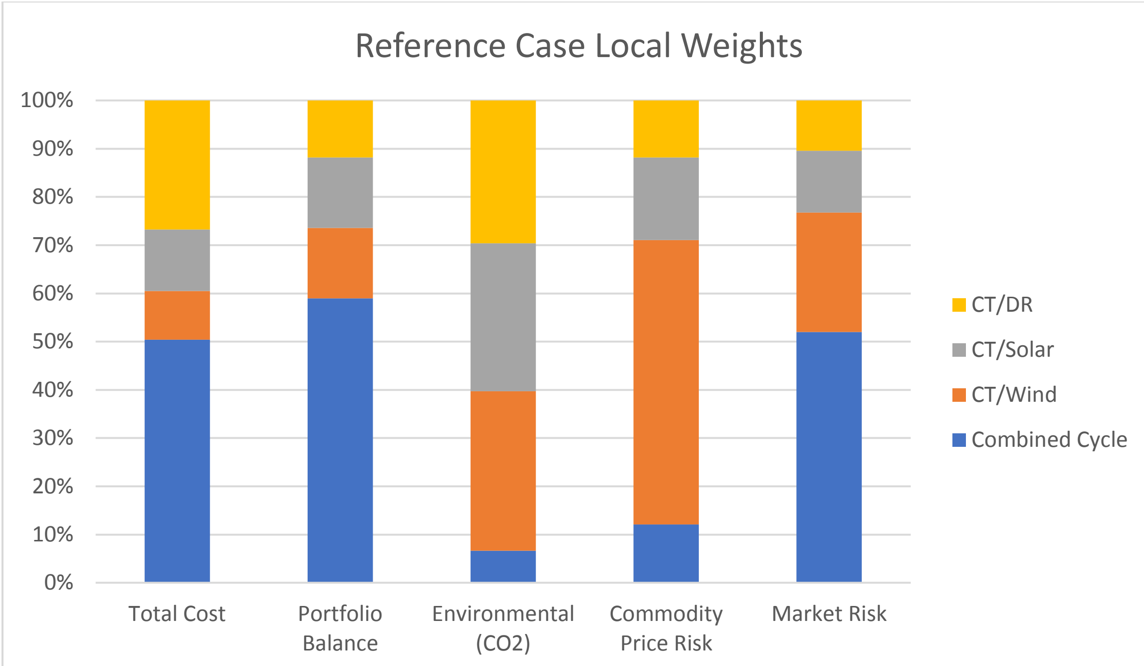


Figure 43 - IRP Portfolio Local Weights for Reference Case

This chart is interpreted by looking at the share of each vertical bar. In DTE's analysis, the Combined Cycle portfolio "wins" about 51% of the value for the Total Cost metric in the Reference case. Similarly, the CT/Wind portfolio shows the best result in the Commodity Price Risk metric, taking 59% of that metric's total value. The three non-combined cycle portfolios do about equally as well in the Environmental category, splitting the pot with roughly 30% each, with the Combined Cycle falling short in this instance.

Q. WHAT IS THE FINAL STEP IN THE AHP PROCESS?

A. At this point, DTE has calculated the weights associated with the SME's preferences and probabilities for the criteria, scenarios, and sensitivities. It has also calculated the results of the different modeling runs for each criteria as expressed through its metric proxy. The final step in this process is to multiply each value from the AHP decision tree by the corresponding metric weight and add up the results. Since each step has used normalized values (that is, the totals add up to 1), the sum of all these products across the four modeled portfolios will also add up to 1. The final results from DTE's AHP analysis are shown in Table 14 below.

IRP Portfolio	Final Score
CC	0.402
CT + Wind	0.235
CT + Solar	0.160
CT + DR	0.203
Total	**1.000**

Table 14 - AHP Final Results

DTE's AHP Analysis Process and Methodology Contain Major Flaws

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. Here, I begin to explain the many concerns that I have with DTE's AHP analysis. I discuss in turn several process problems before turning to a more detailed analysis of the many methodology shortcomings. I discuss issues with how DTE characterizes the major IRP evaluation criteria, followed by concerns with the AHP methodology itself. Finally, I synthesize results from the Stochastic analysis with the AHP analysis to demonstrate the brittleness of the AHP results.

Q. PLEASE PROVIDE AN OVERVIEW OF THE CONCERNS YOU WILL BE ADDRESSING IN THIS SECTION.

A. I have a number of criticisms of the AHP analysis, spanning almost all of the steps discussed previously. These concerns are summarized here and then discussed in more detail below.

- DTE used only internal SMEs, and it was unclear how values from departments were calculated.
- DTE's SMEs occasionally had substantially opposite opinions on pairwise comparisons.

- The assumptions in the Alternative Portfolios are inconsistent with the remainder of the IRP.
- The optimal value for the Portfolio Balance metric is not used in the assignment of the metric weights.
- The Market Risk metric is flawed.
- The assignment of a heat rate to renewable energy and treatment of nuclear fuel volatility in the Commodity Price Risk metric is flawed.
- The degree of preference for one value over another appears to be based on a faulty assumption.
- The methodology to convert modeled results into local weights is based on arbitrary assumptions and produces non-meaningful results.

When taken together, the above concerns combine to preclude any reasonable conclusions from being drawn from the AHP analysis. The alternative portfolios were not constructed under the same rules as the remainder of DTE's ITP. The use of net sales in the Market Risk metric obfuscates the actual risk from market transactions. But most critically, the method used to create the final local weights produces random results when calculated with real-world variations in inputs.

Because the AHP analysis cannot be relied upon, DTE's position that its Proposed Project is a superior result than a wind-, solar-, or DR-centered portfolio is unsupported by this risk assessment.

DTE's Choice of Subject Matter Experts and Alternative Portfolios are Problematic

Q. PLEASE EXPLAIN YOUR CONCERNS ABOUT DTE'S CHOICE OF SMES.

A. As indicated in WP KJC-317, DTE used five different SMEs to perform the criteria and scenario pairwise comparisons. Four of the scores are from individuals, and one is from the "IRP Group." For the load and capital sensitivities, DTE only provided a single data point. The load sensitivity was from "Load Forecasting", while the capital sensitivity was from "MEP", the Major Enterprise Projects department.

All of these parties are internal to DTE, and no outside party reviewed any of the inputs to the AHP analysis. (ELPCDE-5.8, Ex. ELP-53 (KL-53)) While DTE's SMEs have many years of experience in their fields, given that DTE's customers are going to bear the burden of any decision that is made, and given that customers might have different views on how important factors such as GHG emission reductions or market access are, it would have been appropriate to consult some external resources when developing the inputs.

While IRP Group value is combined with other SMEs in the criteria and scenario comparisons, the Load Forecasting and MEP values are the only entries for the load and capital cost sensitivities. It appears that a single person within these departments was responsible for these scores. This could be problematic as a single value is more at risk of being an outlier than an average from a group of SMEs.

Q, PLEASE EXPLAIN YOUR CONCERN ABOUT SOME OF THE SME RESPONSES TO THE PAIRWISE COMPARISON ANALYSIS.

A. While a diversity of opinions is often a benefit when trying to establish a central value for a hard-to-quantify figure, some of the responses from the SMEs appear to be outliers. In the Scenario pairwise comparison, several comparisons showed a high degree of variability. For instance, in the High Gas : Aggressive CO2 comparison, four of the five experts provided answers indicating that the Aggressive CO2 scenario was more likely than the High Gas scenario, by fairly strong degrees (the inverse weight of these answers were 7, 5, 5, and 2). However, the fifth SME scored the High Gas scenario as a 3, indicating it was "moderately" more likely to occur than the Aggressive CO2 scenario.

In another example from the Environmental : Commodity Risk comparison in the Criteria analysis, two SMEs indicated a "strong" preference (5) and one indicated a "moderate" preference (3) for environmental results over commodity risk results. However, the other two indicated a "strong" preference (1/5) and "moderate" preference (1/3) for reduced commodity risk over environmental results, almost the mirror image of the first set.

Figures 44 and 45 below show the pairwise comparisons for the Scenario and Criteria comparisons, plotted on logarithmic scale to better mirror the geometric average that is calculated for the group. While the range of opinions for some of the value were very small, indicating a strong consensus among the SMEs, others show a much wider variability.

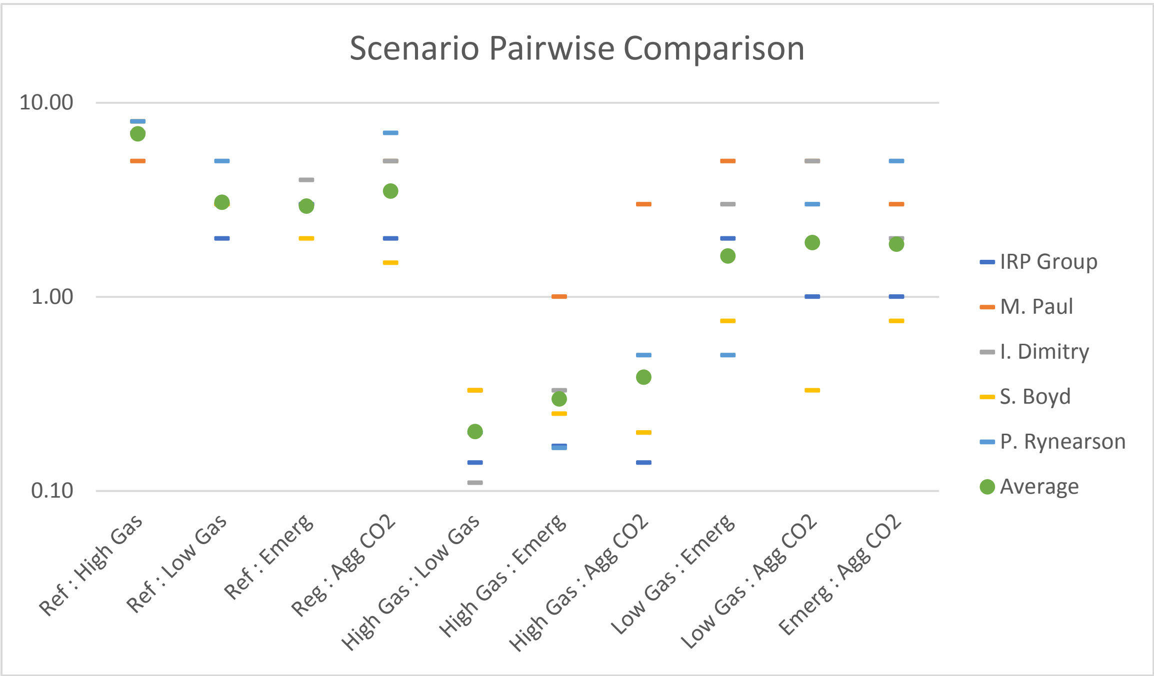


Figure 44 - Scenario Pairwise Comparison

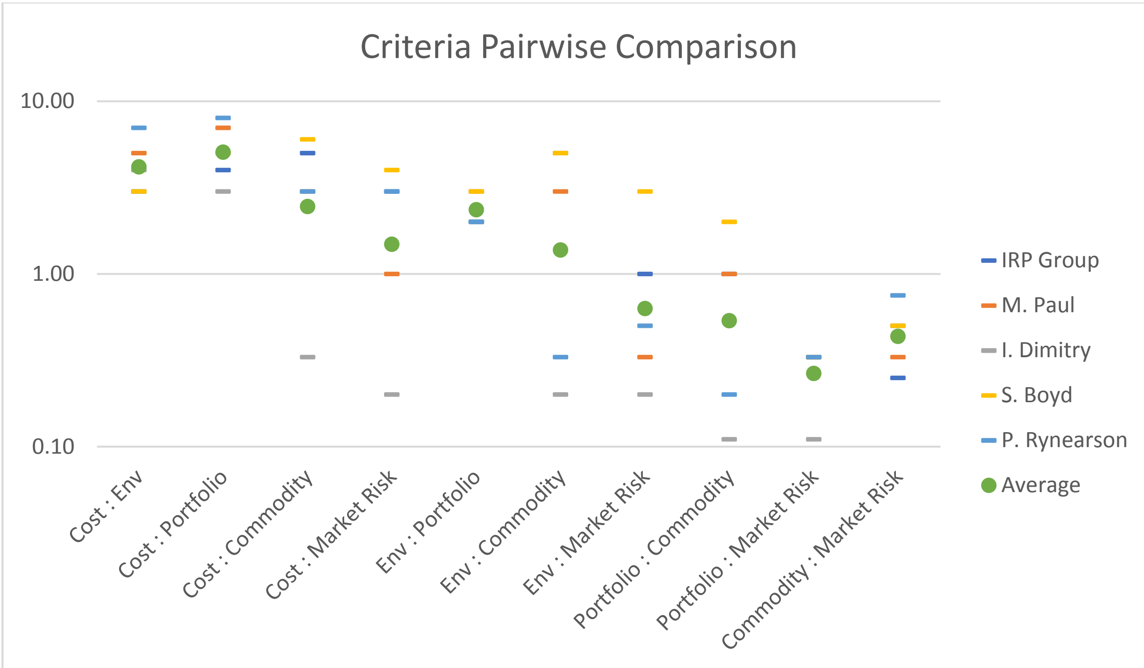


Figure 45 - Criteria Pairwise Comparison

Q. DO YOU HAVE A RECOMMENDATION ON HOW THIS VARIABILITY MIGHT BE ADDRESSED?

A. While I have not done any statistical analyses on the range of answers, the charts above show that some of the values likely have higher confidence levels than others. For instance, there is a strong convergence in the Reference Scenario : Emerging Technology comparison, indicating a higher level of concurrence between the SMEs in that pairwise comparison. But for other values, such as those discussed above, the confidence level is likely lower.

DTE could address this issue by polling more SMEs to increase the number of observations that go into the final value. This will reduce the impact of a single outlier. Alternatively, it could discard the high and low value and take the average of the central three values. Again, this should reduce the impact of any outliers.

Even if the method that DTE uses is appropriate, the relative confidence in these pairwise comparisons is not discussed anywhere in the AHP analysis write-up.

Q. PLEASE EXPLAIN YOUR CONCERNS ABOUT THE ALTERNATIVE PORTFOLIOS THAT DTE DEVELOPED FOR THE AHP ANALYSIS.

A. I have several concerns with the methodology that DTE used to construct its alternative portfolios. First and foremost, it makes an assumption in the AHP that was not used for other modeling runs: that intermittent renewable energy must be "firmed up" with CT resources: "To make the resource plans equivalent on a capacity basis, a block of CT units is required to firm up the non-dispatchable resources." (IRP Report at 214.) At no other point in DTE's modeling does it explicitly pair wind and solar resources with CTs. Further, almost no modeling run selects a CT, much less 4 CTs that are included in the alternative portfolios. I have discussed this issue previously in my testimony.

DTE's stated reason for the alternative portfolios – to make the resource plans equivalent on a capacity basis – is backward. The other modeling runs that DTE performed did not exogenously specify which fossil resources were built. Rather, it defined specific solar, wind, EE, and DR resources and let the model solve for the optimal outcome to meet its capacity requirements. This outcome might include the construction of new resources or other market purchases, but it was assured to meet DTE's capacity obligation. If DTE wanted to explicitly prevent the selection of a NGCC plant by the model, it could have easily prevented the model from doing so.

But by hardcoding in four CTs with combined 877 MW of firm capacity, DTE short-circuits the entire point of modeling the portfolio. Rather than the model choosing what other resources to procure, DTE forced the answer upon the model. There is nothing magical about the 1,100 MW that it is attempting to duplicate, other than that was the rough size of the NGCC unit that it was modeling. DTE's obligation is to meet its resource adequacy obligations, not to build 1,100 MW of capacity in 2022.

Aside from this, DTE did not attempt to model anything other than the most reductive alternatives: x MW of capacity from wind, solar or DR, and (1,100 – x) MW of capacity from CTs. These are not realistic portfolios, as evidenced by the fact that only four of the 36 scenarios or sensitivities listed in Section 11.6 of the IRP Report built even a single CT, while none built four. DTE did not model any increase in energy efficiency beyond the Reference case assumptions, despite having demonstrated the benefits of higher energy efficiency in the IRP. It did not increase demand response in the wind and solar portfolios, despite the highly cost-effective nature of those programs. There is no evidence that the four CTs are the optimal resources when paired with the solar, wind, or DR assets, because DTE did not allow the model to run without the four CTs as a constraint.

DTE also changes its assumptions on the capacity value of solar from the IRP Report. While DTE indicates the solar portfolio was constructed with "500 MW solar (2017-2023)" (IRP Report at 214), the accompanying workpaper shows that 208.2 MW of solar is added in 2023 (WP KJC-314). In other analyses, DTE has used a 50% capacity credit value for solar, and has discussed MW in terms of MW_{AC}. Here, DTE has reduced its capacity credit value to 41.5%, a departure from the rest of the IRP.

Further, the timing of the construction of wind and solar resources in the alternative scenarios is different from the IRP report. The solar and wind resources are not added between 2017 and 2023, as suggested in the IRP Report, but rather all added in 2023. (WP KJC-314, KJC-315.) This is meaningful as the federal ITC and PTC have either expired or diminished by 2023. While DTE's modeled solar and wind capital costs do decline between 2017 and 2023, they do not fall enough to make up for the loss of the federal tax credits. DTE is unfairly disadvantaging the wind and solar resources by delaying the installation of the facilities and is in direct contradiction to the description in its IRP Report.

Q. PLEASE SUMMARIZE YOUR CONCERNS ABOUT THE ALTERNATIVE PORTFOLIOS THAT DTE DEVELOPED FOR THE AHP ANALYSIS.

A. The development and modeling of the alternative portfolios is flawed in many ways. DTE's decision to force 1,110 MW of resources into the model is inconsistent with the remainder of the IRP. It does not attempt to construct a meaningful alternative, but models a reductive alternative. DTE changes the capacity credit assigned to its solar resource. Finally, the timing of the builds is neither optimized to take advantage of the federal tax credits, nor consistent with the narrative found in the IRP Report.

The AHP Analysis' Key Criteria Definitions Suffer from Flaws

Q. PLEASE EXPLAIN YOUR CONCERN WITH THE DEVELOPMENT OF THE PORTFOLIO BALANCE CRITERIA AND METRIC.

A. The Portfolio Balance criteria is intended to correspond to the IRP Planning Principle of "Flexible and Balanced." DTE mapped this criteria to the metric of percentage of capacity from peaking resources. While the four other metrics do not have a "target" value (the lowest value is the *de facto* best result), DTE does provide some additional analysis on the Portfolio Balance metric.

A rough analysis using the 2024 load duration curve is found in a tab within WP KJC-318. In this analysis, a note indicates that the peakers run 5-8% of the time in "the cases" (presumably in the cases modeled in the AHP analysis), and that based on the 2024 load duration curve, "this corresponds to an optimal range of 31-37% of the fleet should be peaking capacity." The note continues "We are already over this level in the CC build case. The other cases add even more peakers and take us further from this optimal target." In other words, even the portfolio with the lowest percentage of peaking units exceeded DTE's definition of the optimal portfolio balance.

Q. WERE YOU ABLE TO DUPLICATE THE RESULTS OF THIS ANALYSIS?

A. Not exactly, but I was able to produce similar results. I was able to recreate the 2024 load duration curve using data from WP KJC-36. The graph in the analysis does not have corresponding data, but the peak value hardcoded into DTE's analysis does not match the peak from WP KJC-36. I also calculated the weighted average factor for each portfolio analyzed in the AHP using data from WP KJC-313 through KCJ-316. These values are summarized in Table 15 below and match the rough DTE analysis fairly well. For reference, peaking values of 5% and 8% are included, with corresponding optimal peaking values calculated from the WP KJC-36 load duration curve.

	Reference	Solar	Wind	DR	DTE Min	DTE Max
CF	6.2%	8.3%	9.0%	8.3%	5.0%	8.0%
Load	6,918	6,556	6,446	6,555	7,159	6,602
% of Peak	66.9%	63.4%	62.3%	63.3%	69.2%	63.8%
1 - %	**33.1%**	**36.6%**	**37.7%**	**36.7%**	**30.8%**	**36.2%**

Table 15 - Optimal Peaking Percentage

As discussed earlier, what DTE considers to be the optimal mix of resources today might not be the most appropriate in the future. As more intermittent but zero-carbon solar and wind resources are added, DTE will need more operational flexibility, not less. Preferring baseload generation over peakers will not provide the flexibility needed to meet future CO_2 reduction goals.

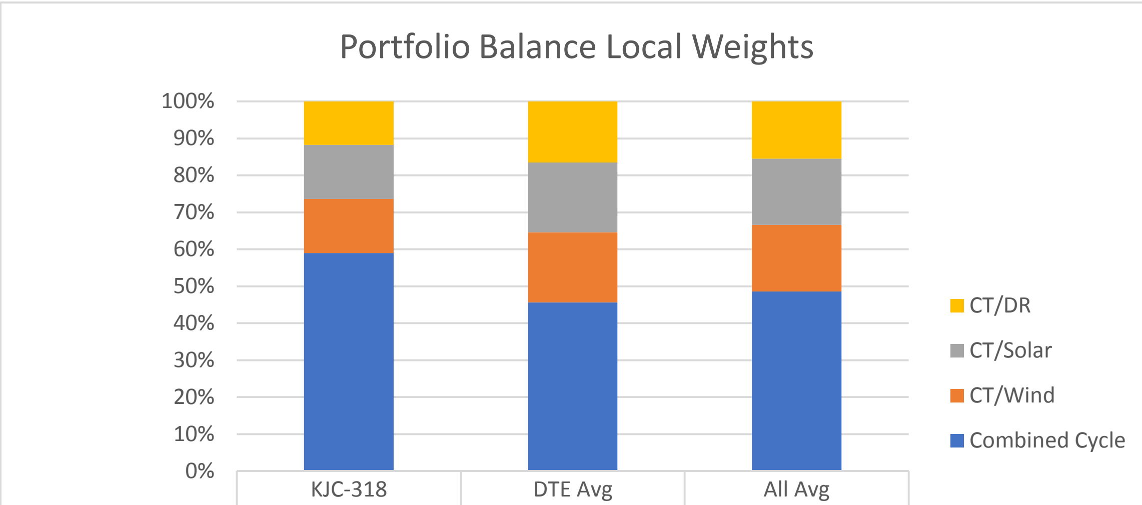
Even under DTE's methodology for determining the optimal peaker ratio in the portfolio, the best value would be between 30.8% and 37.7%. Using an average of all these portfolios results in an optimal value of 35.2%. Taking the average of DTE's assumptions would result in an optimal value of 33.5%.

Q. WHY ARE THESE VALUES RELEVANT TO THE SCORING OF THE PORTFOLIO BALANCE METRIC?

A. As discussed further below, DTE's analysis considers each portfolio relative to each other when calculating scores. For the other criteria, no optimal value is produced. It is assumed that costs, emissions, price volatility, and net sales should be minimized. However, DTE went out of its way to perform an analysis identifying the best result for the peaker percentage value.

But despite having calculated this value, DTE did not use it in its analysis. Instead, along with the other four variables, it simply assumed that lower was better.

This decision makes a difference since the local weight calculation is based on part on the range between the portfolio result and the "best" result. Figure 46 below duplicates the results of DTE's local weight calculation methodology for its original values and the two averages discussed above. This change makes a meaningful difference. The combined cycle case falls from a score of 59% to 45%-49%, while the other three scenarios pick up the difference.



	KJC-318	DTE Avg	All Avg
CT/DR	0.1179	0.1652	0.1545
CT/Solar	0.1462	0.1892	0.1800
CT/Wind	0.1462	0.1892	0.1800
Combined Cycle	0.5897	0.4564	0.4856

Figure 46 - Portfolio Balance Local Weights

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE MARKET RISK CRITERIA.

A. The Market Risk criteria is embodied in the net sales metric of the modeling runs. While other metrics such as fuel volatility and portfolio balance are taken from a single data point from a single year, the net sales is different in two ways. First, the metric is calculated as the sum of all market purchases less the sum of all market sales. Second, this value is calculated over the years 2022-2030 rather than from just 2024. (WP KJC-318.)

There is no indication as to why the energy sales were calculated over a nine year period while the fuel volatility and portfolio balance are from a single year. Clearly, how the portfolios compare in fuel volatility and portfolio balance are relevant for more than just one year out of the analysis horizon.

More importantly, the net sales metric is not the best way to capture market risk. DTE's use of net sales overlooks two critical factors that one must incorporate to truly compare market risk. The first is that the netting process removes the impact of scale from purchase and sales. The second is an incorrect embedded assumption that purchase and sales offset each other in both timing and cost.

Q. PLEASE EXPLAIN HOW NETTING SALES AND PURCHASES HIDES MARKET RISK.

A. DTE's explanation for this metric is found in the IRP Report. It states "[s]ince risks are associated with depending too much on the market, for both sales and purchases the closer to zero net purchases was preferred for these criteria." (IRP Report at 211.) Aside from making a confusing, blanket statement with no supporting evidence, it appears from the statement that DTE wishes to minimize exposure to the market for both sales and purchases.

The most natural way to do this would have been to take the sum of the absolute value of sales and purchases. If in a given year DTE sold 500 GWh into the market and purchased 400 GWh from the market, it was exposed to 900 GWh of market transactions in the year. If DTE sold 1,500 GWh into the market and purchased 1,400 GWh from the market, it would be exposed to 2,900 GWh of transactions. The second value is much higher than the first, and reflects the incremental risk associated with additional market transactions. This approach could be reasonable for calculating the market risk of sales and purchases.

However, by netting the transactions against each other, DTE obfuscates the true market risk. In the above example, net sales are 100 GWh for both scenarios, despite the latter exposing the company (and more importantly, its customers) to more than 3 times as many market transactions. DTE's flawed analysis treats these scenarios equally.

However, DTE does not only do this within a given year, it does it over nearly a decade of modeled results. It cannot be assumed that the market risk for 100 GWh of sales in 2022 will be the same as for 100 GWh of purchases in 2030. By allowing sales to net across years, DTE further misses variability that might arise in markets in the future.

Q. PLEASE EXPLAIN DTE'S EMBEDDED ASSUMPTION REGARDING THE OFFSET OF PURCHASES AND COSTS.

A. By choosing to net market sales and purchase both within a year and across multiple years, DTE is implicitly assuming that the risk and value of these transactions are identical. Although it is not clearly defined, it is reasonable to assume that DTE includes both price volatility risk and price value risk when discussing risks "associated with depending too much on the market."

Price volatility risk increases the further in time one goes forward. With the exception of a PPA, future prices are not guaranteed. Given that fuel prices can and do fluctuate, locking in a price for a market transaction today is easier and less expensive than locking in a price for ten years from now. But by netting purchases in 2022 against sales in 2030, DTE ignores this risk.

The other risk is price value risk, or the risk that the value of a sales transaction might be higher or lower than the value of the corresponding purchase transaction. The timing of sales and purchases will be a function of the portfolio mix. A portfolio heavy in solar might produce more energy during the day which can be sold at peak prices. A portfolio with additional demand response could avoid purchases during the same peak periods, reducing costs. Since Strategist produces hourly values for market sales and purchases, DTE could have determined the value of the net sales. It did not do so.

Q. PLEASE EXPLAIN YOUR CONCERN WITH DTE'S RENEWABLE ENERGY HEAT RATE ASSUMPTIONS AND TREATMENT OF NUCLEAR ENERGY IN THE COMMODITY PRICE RISK METRIC.

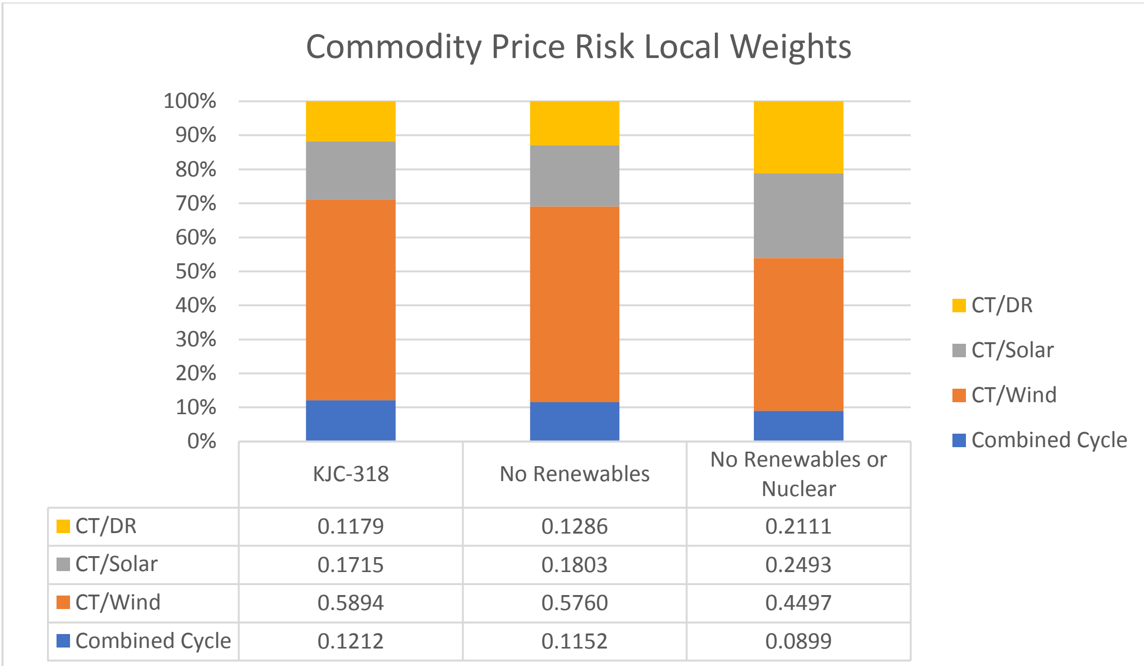
A. When calculating the Commodity Price Risk metric, DTE begins by calculating the share of fuel in MMBTUs for each scenario. In this calculation, the heat rate (BTUs/MWh) for renewable energy is set to 10,000. Given that heat rate is a measure of the energy of combustible fuel needed to produce a unit of energy in a generator, it has no relevance to renewable energy that derives its energy from the sun or wind.

DTE assigns nuclear energy a price volatility score of zero despite having no data to support this figure. While all other fuel sources use a risk variable equal to the standard deviation divided by the average price over an 18 year price history, DTE has hardcoded values for nuclear fuel prices. Further, instead of calculating the risk variable using these hardcoded values, it assigns a value of zero to the fuel. It is unclear if DTE truly believes that price volatility is zero for nuclear fuel, or if it was trying to only capture the volatility of fossil fuels. If it is the former, then DTE should have provided supporting data. If it is the latter, then DTE should have excluded the MMBTUs assigned to nuclear energy in the final fuel mix.

Q. WHAT IS THE RESULT OF THESE TWO DECISIONS?

A. In DTE's analysis, the Commodity Price Risk under-reports the risk associated with fossil fuel purchases. The inclusion of a heat rate for renewables impacts the total share of fuel, which in turn affects the calculated Commodity Price Risk metric. Likewise, excluding nuclear fuel to produce a fossil-fuel only risk metric further changes the values.

Using data from WP KJC-318, I have produced two alternative calculations for this metric. As seen in Figure 47 below, when renewables are excluded from the calculation, the NGCC portfolio loses some value, while the Solar and DR gain. If nuclear energy is removed as well, the NGCC loses further value, and the Solar and DR portfolios gain value from the Wind portfolio.



	KJC-318	No Renewables	No Renewables or Nuclear
CT/DR	0.1179	0.1286	0.2111
CT/Solar	0.1715	0.1803	0.2493
CT/Wind	0.5894	0.5760	0.4497
Combined Cycle	0.1212	0.1152	0.0899

Figure 47 - Commodity Price Risk Local Weights

DTE's Methodology for Calculating Local Weights is Broken

Q. PLEASE DISCUSS YOUR CONCERN ABOUT HOW PREFERENCES BETWEEN DIFFERENT OUTCOMES IS CALCULATED.

A. In the introduction to this section, I mentioned a Q Value several times. In DTE's analysis, this represents the mapping between the linear position between 0 (worst result) and 1 (best result) and the preference for that value. DTE uses a value of 5 for this step, and transforms the interval scores into the Q Value by the formula $Q\ Value = 5^{Interval}$. Mathematically, the value 5 defines the ratio between the best value and the worst value.

Q. WHAT IS THE IMPACT OF CHANGING THIS VALUE?

A. It can have reasonable impact on the local weights. Using the Total Cost from the Reference scenario as an example, I have recalculated the weights using a Q value of 1 to 9 in Figure 48 below. When Q = 1, there is no preference and all values get one-quarter of the value of the metric score. As Q increases, the "best" option steadily gains value. With a Q of 2, the NCGG score increases to about one-third of the total. With a Q of 3, it is just over 40%. By the time Q = 5, it hovers around 50%.

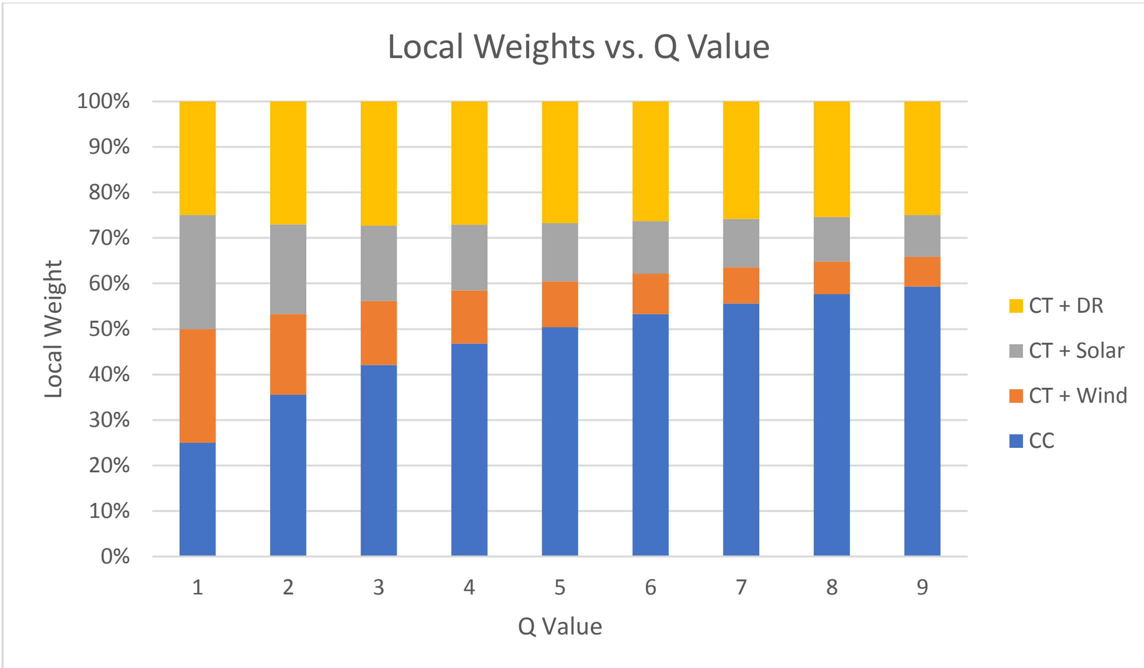


Figure 48 - Local Weights vs. Q Value

Q. DOES DTE PROVIDE AN EXPLANATION FOR WHY IT CHOSE 5 INSTEAD OF ANOTHER NUMBER?

A. The only source I could find for the choice of 5 in this step is a note in WP KJC-318 that reads "5 chosen because it is the middle of the 1 to 9 scale." However, the 1 to 9 scale that was used by the SMEs in the pairwise comparison does not have a "default" value of 5 just because it is in the middle of the scale. Given the impact of this value, one would hope for a more robust justification.

Q. WHILE YOU HAVE POINTED OUT MANY CONCERNS WITH HOW INDIVIDUAL METRICS WERE CALCULATED IN THE AHP ANALYSIS, DO YOU HAVE A MORE GENERAL CONCERN ABOUT HOW THE LOCAL WEIGHTS ARE CALCULATED FOR ALL METRICS?

A. Yes. The most troubling part of DTE's alternative portfolio analysis is the final step that translates the individual values for each metric into a local weight for each portfolio. DTE's choices in this step produced skewed weights that do not reflect how one would objectively measure portfolios against each other.

Specifically, DTE's method of comparing the portfolios against each other produces results that are independent of scale. It might be reasonable to value $5 in savings 5 times as much as $1 in savings, and it also might be reasonable to value $500 million in savings 5 times as much as $100 million in savings. But would it be reasonable to prefer both of these outcomes equally? Of course not. Any rational person would rather save $500 million instead of $5, but the Q Value calculation does not distinguish between these outcomes.

Further, the weight assigned to the best outcomes appears to have been selected based on an incorrect interpretation of the AHP methodology. The combination of these factors results in all portfolio local weigh calculations being arbitrary and thus inappropriate.

Q. PLEASE EXPLAIN HOW DTE CALCULATES THE LOCAL WEIGHTS FOR A GIVEN METRIC.

A. DTE's methodology is contained in WP KJC-318. The first step in the process is to collect the results from each of the scenarios and sensitivities that were run for the four alternative portfolios. As discussed above, some of these values are taken directly from the modeling run, while some are further processed to produce the needed data. DTE's example for the Total Cost for the Reference portfolio is duplicated below in Table 16.

Alternative	Total Cost ($mm)	Residual Cost ($mm)	Interval level Score	Q Value	Local Weight
CC	15,768,015	-	1.000	5.000	0.504
CT + Wind	16,237,132	469,117	0.000	1.000	0.101
CT + Solar	16,167,743	399,728	0.148	1.269	0.128
CT + DR	15,952,727	184,712	0.606	2.653	0.267

Table 16 - Portfolio Local Weight Calculation

The scoring method is based entirely on the interval level score, which is based entirely on the range of alternatives to be analyzed. Above, the least expensive alternative gets a score of 0. The most expensive gets a score of 1. Portfolios in between are just a normalized interpolation between 0 and 1. This relationship is clearly demonstrated in Figure 49 by plotting the metric value against the interval level score. Note the R^2 value is 1, indicating a perfect linear fit.

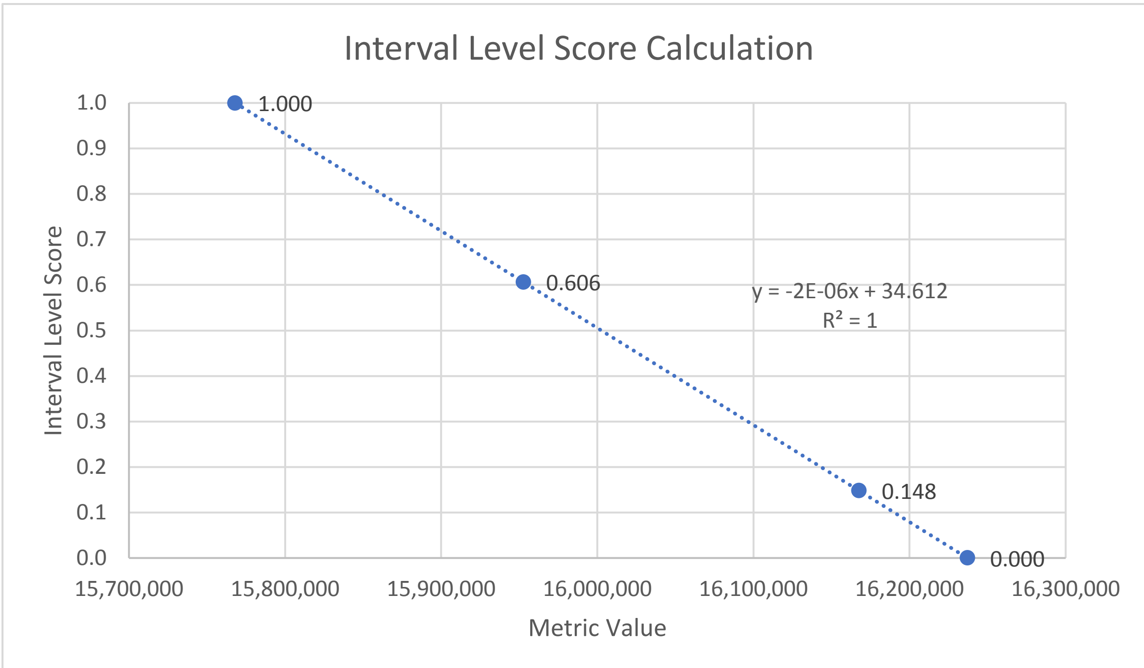


Figure 49 - Interval Level Score Calculation

This interval score is then transformed into a value between 1 and 5 based on an exponential relationship to produce the Q Score. The local weights are simply the alternative's normalized fraction of the sum of the Q scores (that is, $Q_x / \sum Q$).

Q. HOW IS THIS METHOD AFFECTED BY THE SCALE OF THE METRIC VALUES?

A. It is fully dependent on the specific metric values, but completely independent of the relative scale of the specific metric values. Simply put, it is possible to duplicate the local weights of the metric with an infinite number of alternative portfolios. I have created a second hypothetical set of alternatives where the maximum value and minimum value differ by $100,000, rather than by $469,117,100 as in the Reference scenario. It is a trivial exercise to develop two other portfolios that will produce the exact same interval levels (and thus the same local weights) as the original set, as seen below in Figure 50 (note the difference in the Metric Value scale).

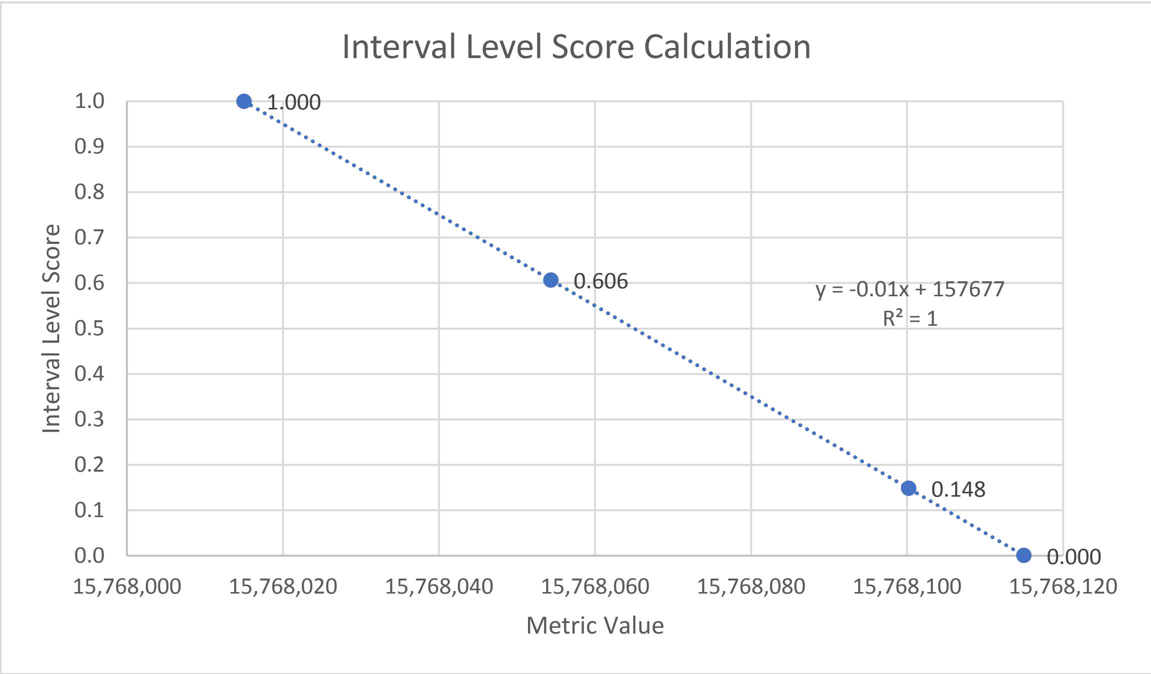


Figure 50 - Interval Level Score Calculation - Alternative

This lack of scale-dependency is a problem. The goal of calculating the local weights is to quantify the preference of one result over the other. One might conclude that saving $469,117,100 justifies one portfolio collecting just over 50% of the "value" for the Total Cost metric. But saving a tiny fraction of this amount could result in the same local weights, obscuring the true degree of preference that one would have for one portfolio over the others. Total Cost determines just over 40% of the final portfolio value. Knowing that half of the weight of this calculation could be given to a portfolio that "wins" by a single dollar out of nearly $16 billion is not comforting. However, this issue is inescapable in DTE's methodology.

The Final Step in the AHP Analysis Buckles Under Real-Life Uncertainty

Q. DO YOU HAVE OTHER ISSUES WITH THE METHODOLOGY TO ASSIGN THE METRIC LOCAL WEIGHTS?

A. Yes. The modeling results are taken directly to calculate the interval level scores, which are in turn directly translated into the local weights. However, the single value of the reported metric contains no information about its statistical uncertainty.

It is said that all models are wrong, but some are useful. I do not doubt that the modeling that DTE did is useful to help inform the issues in this case, but to suggest that it produces results with such a small degree of uncertainty that a single point value from a modeling run can be used to establish the foundational metric on which one alternative portfolio is compared to another is a step too far.

It is worth taking a step back to understand just how many variables go into the modeling of each portfolio. Prices for many fuels are forecasted 25 years out, hourly or weekly loads are projected by economic sector and transmission zone for decades, technology price forecasts are developed well beyond what is certain today, and market energy and carbon prices are forecasted as well. This is, of course, the nature of modeling complex systems, and DTE understands that uncertainty exists in the future, which is in part why it developed so many different scenarios and sensitivities.

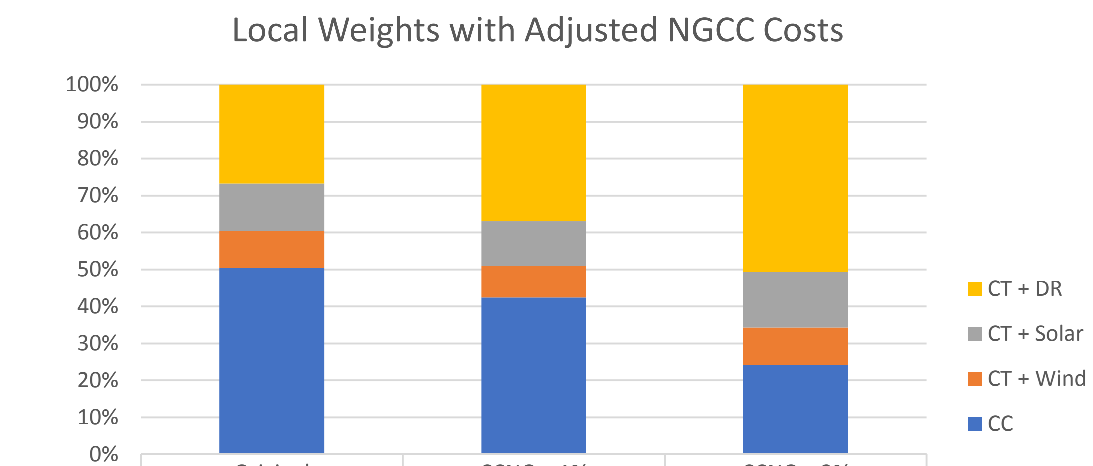
But rather than incorporate this acknowledged uncertainty into this part of the AHP analysis, DTE constructed a methodology that relies on a single value from a modeling run, with no context for how it might change under different circumstances. And given how much uncertainty is embedded in the model, the results of local weight calculation for each metric very well may fall within the aggregate margin of error of the model itself and therefore cannot be relied upon.

Q. HOW DOES THIS UNCERTAINTY FACTOR INTO THE DEVELOPMENT OF THE LOCAL WEIGHTS?

Each variable in model has uncertainty associated with it. While one variable might deviate in a way that lowers the expected cost, and another might deviate in a way that increases the expected cost, the range of possibilities from the combination of the two variables is larger, not smaller, than from the variability produced by a single variable. Given the dozens and dozens of variables in DTE's model, the combined uncertainty around any single metric, such as PVRR or CO2 emissions, is almost certainly higher that the difference between the metric values from modeling runs.

However, the local weight calculation takes the single output value as gospel. The methodology is entirely dependent on the exact results of the model runs. By definition, the portfolio with the best outcome gets a value of 1, and the worst outcome gets a value of 0. The other two are always in between. If one shifts a single variable relative to the others, it changes the weights for all of them.

If one were to increase the Total Cost of the NGCC portfolio by just 1% or 2%, the local weights would change substantially. As seen in Figure 51 below, adding 1% to the NGCC cost drops its value by 16% (from 0.504 to 0.424). Increasing its cost by just 2% flips the weights, with the Demand Response alternative now dominating the Total Cost metric.



	Original	CCNG + 1%	CCNG + 2%
CT + DR	0.267	0.369	0.507
CT + Solar	0.128	0.122	0.150
CT + Wind	0.101	0.085	0.101
CC	0.504	0.424	0.242

Figure 51 - Local Weights with Adjusted NGCC Costs

Q. DO SMALL ADJUSTMENTS IN OTHER MODELING RUNS ASIDE FROM THE REFERENCE CASE PRODUCE SIMILAR CHANGES?

A. Yes. In the Reference scenario, the most expensive alternative portfolio is 3% higher than the least expensive. In the other scenarios and sensitivities, the range is roughly 2%-4%. So in every scenario, changes on the order of 1% to 2% of the total cost could have major impacts on the local weights for the Total Cost metric. And considering that the Total Cost metric comprises over 40% of the final portfolio score, this is very problematic.

Q. DO YOU HAVE ANY INSIGHT INTO HOW MUCH UNCERTAINTY THERE IS AROUND THE TOTAL COST METRIC IN THE MODEL?

A. Yes. In addition to the AHP analysis, DTE performed a stochastic analysis on the same four alternative portfolios. While I discuss my specific concerns about that analysis below, its results can still inform the degree to which the Total Cost metric shifts depending on the underlying assumptions. Although the AURORA model used for the stochastic analysis is different than the Strategist model used for the AHP analysis, DTE discussed in its IRP Report that the results between the two models were generally consistent with each other. Strategist calculates the Total Cost in the form of the NPRR, and AURORA calculates the portfolio cost as the NPV of capital expenditures, fixed and variable O&M, and net market sales. (Exhibit A-5 Appendix Q.) The values are different from each other, but they both represent a form of total cost associated with a particular scenario.

DTE provided the detailed results of the 200 runs performed in the stochastic analysis in ELPCDE 5.13, Ex. ELP-54 (KL-54). From this, I compiled some basis statistics about each alternative portfolio in Table 17 below.

	Portfolio 1: CC	***Portfolio 2: Wind***	***Portfolio 3: Solar***	***Portfolio 4: DR***
Mean	$57,676,520	$58,289,680	$58,270,378	$57,816,943
Standard Deviation	$18,409,218	$18,379,980	$18,495,364	$18,446,476
Minimum	$36,126,406	$37,445,768	$36,324,205	$35,997,493
Maximum	$170,719,664	$171,953,772	$172,337,280	$171,630,709

Table 17 - Alternative Portfolios Descriptive Statistics

The mean cost values from AURORA are almost exactly 3.6 times larger than the corresponding Total Costs from the Strategist AHP scenario result, showing good consistency between the two models. But one can see that while the mean values correspond fairly well to the AHP figures, there is a huge range of outcomes when the portfolios are exposed to different inputs. The lowest value produces total costs that are roughly 38% lower than the average, which the maximum value is nearly three times as expensive.

There is also a sizable standard deviation of the portfolio, indicating that wide range of plausible outcomes. As discussed before, the local weight is entirely dependent on the relative value of the Total Cost metric. Given the variability of each portfolio, it follows that the relationship between the individual Total Cost metrics will also vary. And this is exactly the case.

Q. WERE YOU ABLE TO CALCULATE THE TOTAL COST LOCAL WEIGHTS FOR EACH RUN OF THE STOCHASTIC ANALYSIS?

A. Yes. Using the same methodology and calculations as DTE used in the AHP analysis, I produced local weights for every run of the Stochastic Analysis. The results in Figure 52 are both expected and extremely revealing: the variability in the local weights under different input assumptions renders absurd DTE's use of a single Total Cost value in the AHP analysis.

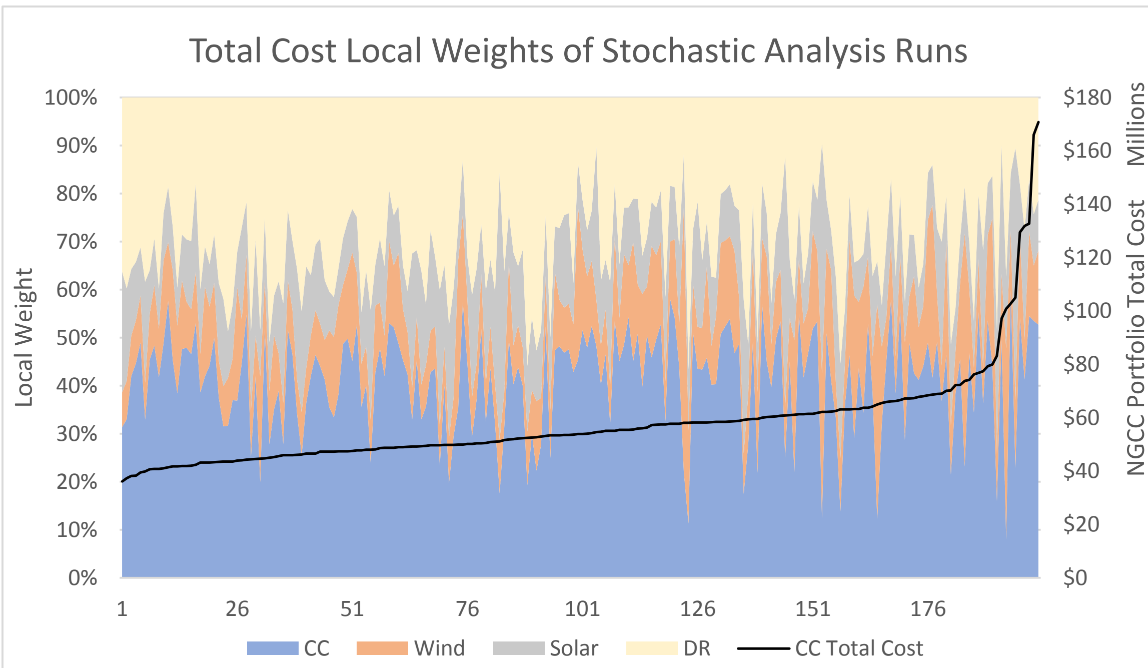


Figure 52 - Local Weights of Stochastic Analysis Runs

There is no discernable relationship between the local weights and the total cost of the run. There is a huge range of weights for each alternative portfolio. The NGCC captures as much as 60% of the value in one run, and as little as 8% in another. Similar ranges are found for each variable: wind ranges from 7% to 55%, solar from 7% to 56%, and DR from 10% to 57%. It is simply not reasonable to assume any single data point from this chart accurately represents the local weight of the Total Cost.

Q. WOULD TAKING THE AVERAGE OF THE INDIVIDUAL LOCAL WEIGHTS PRODUCE A MEANINGFUL RESULT?

A. I do not believe so. The mathematical transformation between the Total Cost and the local weights is not linear. It is dependent on both the individual results of a given portfolio as well as the results of the other portfolios. Further, using the average local weight as a proxy for the expected portfolio implicitly assumes that each of the 200 stochastic runs has an equal chance of occurring. Given the wide range of total cost results, this is not the case. Under these circumstances, taking a simple average of the results is unlikely to properly reflect the randomness of the underlying process.

Q. WOULD YOU ANTICIPATE SIMILAR FINDINGS IF YOU PERFORMED THIS ANALYSIS ON THE OTHER METRICS?

A. Yes. While the stochastic analysis workpapers did not contain sufficient information to reproduce this analysis for the remaining four metrics, it is reasonable to assume that the same factors that caused substantial variation within the Total Cost local weight calculation would manifest in the other scenarios as well.

Q. PLEASE SUMMARIZE YOUR CONCERNS ABOUT THE AHP ANALYSIS

A. DTE did not consult outside parties when developing the pairwise comparison of the different metrics. Some of the scores from the SMEs varied considerably which, when combined with the relatively small number of SMEs, raises some concern about the degree to which outliers impacted the final pairwise comparison scores.

DTE's construction of the alternative portfolios was done in a manner different than all other modeling runs. Rather than letting the model solve for the amount of capacity that was needed alongside a defined quantity of wind, solar, or DR, DTE forced in 950 MW of CTs based on a faulty assumption that intermittent resources need "backing up." Given that no other modeling run naturally produced four CTs, it is suspect whether this portfolio would be viable when compared to other options.

The Portfolio Balance metric is the only one of the five metrics where an "optimal" value is produced, but DTE does not use this in the development of the local weights for this metric. The Market Risk metric is fatally flawed; net sales is simply the wrong value to reflect actual exposure to market risk in energy transactions. Assigning wind and solar heat rates distorts the Commodity Price Risk metric, as does DTE's inclusion of nuclear energy in the final fuel mix. The value used to calculate the value of "best" to "worst" does not appear to have a valid justification.

Most critically, the assumption that the calculation of the local weights from a single modeling run will produce a representative result ignores the substantial degree of uncertainty in the modeling itself. As demonstrated by analyzing the Total Cost results from the stochastic analysis, the local weights have a high degree of volatility under different modeling inputs, and there is no obvious reason to expect that a single value plucked from a single modeling run will be representative of the expected performance of the portfolio under real-world conditions. This observation likely applies to the other four metrics as well. This is not to say that DTE made a technical mistake in their analysis, but rather that its assumption that its methodology will produce meaningful results despite the uncertainty of the modeling is misguided.

Q. WHAT IS YOUR CONCLUSION ABOUT THE RELEVANCY OF THE AHP ANALYSIS TO THIS PROCEEDING?

A. It is irrelevant. Using only internal SMEs to develop its ratings, DTE scored alternative portfolios against each other under a completely different set of rules. The final step that produced the criteria scores is both flawed and brittle, producing extremely volatile results under a set of real-world inputs. The AHP analysis as DTE performed it is not an objective analysis that can be relied upon to draw conclusions between its Proposed Project and alternative portfolios. As such, it should be discarded.

DTE's Stochastic Analysis Offers Only a Limited View on an Entirely Unrealistic Scenario

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SUBSECTION OF YOUR TESTIMONY.

A. I turn from the AHP analysis and move into the Stochastic analysis. I begin by analyzing DTE's capital cost assumptions for wind and solar, which are substantially higher than values used elsewhere in the modeling. I point out the problem with DTE only analyzing the Total Cost of the portfolio under the Reference scenario while failing to provide insight to the other key metrics. Finally, I analyze in detail the calculation of the Economic Risk metric and how (un)likely those scenarios are. After analyzing these three issues in more detail, I conclude that the Stochastic Analysis does not provide meaningful insight on the relative performance of the various alternative portfolios.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE STOCHASTIC ANALYSIS THAT DTE PERFORMED.

A. While DTE did not provide many details of the inner workings of the AHP Analysis in its IRP Report and Appendices, PACE Global (PACE), who performed the Stochastic Analysis for DTE, did create a detailed summary of its methodology in Appendix Q of the IRP Report. Therefore, I do not provide as much background on the methodology as I did with the AHP Analysis.

The Stochastic Analysis begins by assigning values to key inputs such as load, gas prices, and coal prices. Each variable is assigned a distribution that describes the deviation from the expected baseline forecast. For instance, deviations in load, emission costs, and capital costs were assigned a normal distribution, while deviations in coal and gas prices were assigned a log-normal distribution. For coal and natural gas prices, PACE utilized a "single-factor mean reverting model" and correlation matrices that tended to keep the costs from running too far away from the underlying reference forecast. (ELPCDE-6.1a-c, Ex. ELP-55 (KL-55))

After these distributions and correlations were established, PACE performed a Monte Carlo analysis to produce 2,000 different simulations, each with its own combination of inputs based on the distribution and correlations of the underlying variables. This was too many to run through the model, so PACE used a "stratified sampling" technique to select the final 200 inputs. According to PACE, "this technique makes sure that the distribution tails are captured well." (ELPCDE-6.1e, Ex. ELP-56 (KL-56))

Armed with the raw inputs for each key variable, PACE ran a modified version of its AURORA model to produce the Total Cost results for each combination of inputs. As discussed above, the results of the Total Cost ranged substantially, from about $36 billion to $170 billion. PACE then calculated the average value of each alternative portfolio (the Expected Value), and compared this to the average of the top 10% most expensive runs of each alternative portfolio (the Economic Risk). Based on a comparison between the Expected Value and the Economic Risk, DTE determined that the NGCC portfolio was the best option.

Q. PLEASE DISCUSS YOUR CONCERNS REGARDING THE LIMITATION OF THE ANALYSIS TO TOTAL COST UNDER THE REFERENCE SCENARIO.

A. While Total Cost is an important driver of the overall result in the AHP analysis, it is far from the only important criteria. The AHP analysis assigned Total Cost 40.4% of the final weight of the key criteria, meaning that 59.6% of the result is driven by the other four criteria. (WP KJC-318.) DTE did not provide any insight on how these other variables fared when run through the model with a wide variation of inputs, even though they combine to contribute about 50% more to the final score than does the Total Cost criteria.

Further, the use of the Reference scenario as the underpinning of the inputs again fails to consider other scenarios and sensitivities that were weighed in the AHP analysis. Putting aside for the moment my myriad concerns about the AHP analysis, the Reference case was just one of eight scenarios and sensitivities that were considered. Using data from Table 12 above, we can see how little of the total set of potential futures the Reference case covers. This is done by multiplying the local weights for the Reference Case (0.460) by the Base Load (0.722) by the Base Capital Costs (0.875), which results in just 29.1% of the total.

Combining these two values, we see that inspecting the Total Cost (40.4%) under the Reference Case assumptions (29.1%) means that the Stochastic Analysis is only relevant to 11.7% of the factors that produced the final weight of the AHP Analysis. So even if one were to accept the results of the Stochastic Analysis to demonstrate that the NGCC option is the right choice, it is only the right choice under 11.7% of the total IRP characteristics that DTE deems important to analyze.

DTE's Capital Cost Assumptions used in the Stochastic Analysis are Wildly Overstated

Q. PLEASE DISCUSS THE CAPITAL COST ASSUMPTIONS USED IN THE STOCHASTIC ANALYSIS.

A. The capital costs for wind and solar were provided in WP KJC-320. Upon further analysis, they are substantially higher than the cost projections DTE used in other parts of the IRP, which were already high. Figure 53 below shows the cost projections by percentile for the stochastic analysis along with other forecasts discussed above.

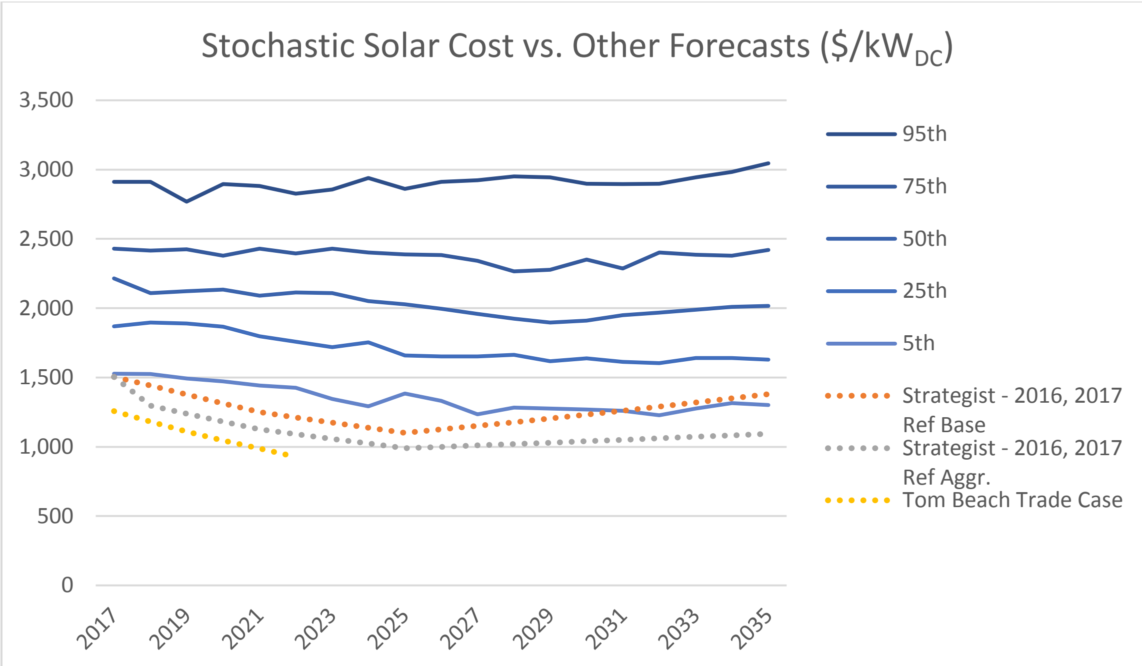


Figure 53 - Stochastic and Other Solar Cost Forecasts

Astoundingly, even the least likely prices of the stochastic analysis (those representing the 5th percentile) are considerably higher than the other Strategist figures, and roughly 30% to 55% higher than Mr. Beach's figures. On the other end of the scale, the "equivalently likely" 95th percentile costs are about 2.5 times higher than DTE's other projections, and roughly 2.5 to 3 times as expensive as Mr. Beach's figures.

The wind capital costs suffer a similar fate, although the differences are not as pronounced. Figure 54 below captures the wind capital costs and shows the other forecasts most closely matching the 25th percentile value from the stochastic analysis.

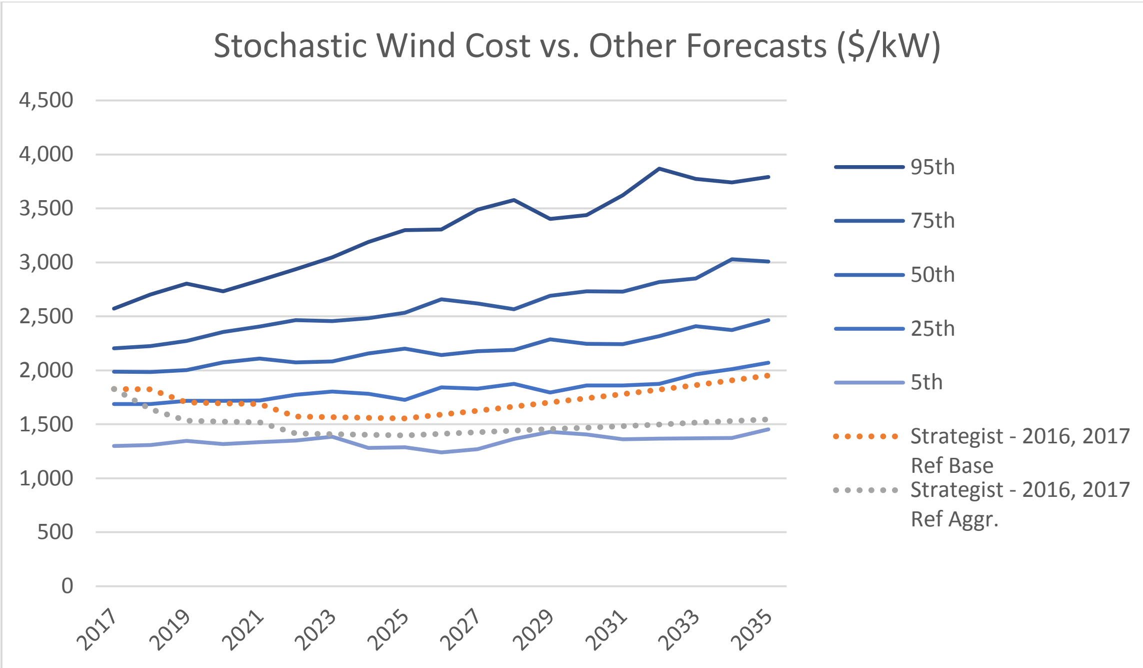


Figure 54 - Stochastic and Other Wind Cost Forecasts

Q. HOW DO THESE COST DISTRIBUTIONS FACTOR INTO THE STOCHASTIC ANALYSIS?

A. The stochastic analysis builds the entire portfolio of wind or solar assets in 2023. By inspecting the actual values used in 2023 and comparing them to the cost projections from other forecasts, we get some idea of what solar and wind costs were used in the various runs. Figure 55 below shows the capital costs that were used in 2023 for solar, along with values from the Strategist Base and Aggressive forecasts along with the 2022 value from Mr. Beach's forecast. Unsurprisingly, almost all of the draws that were used had higher costs than the alternative forecasts. In fact, only 15 runs used costs lower than the Base case, only 3 runs used costs lower than the Aggressive case, and only a single run out of 200 used costs lower than Mr. Beach's 2022 value.

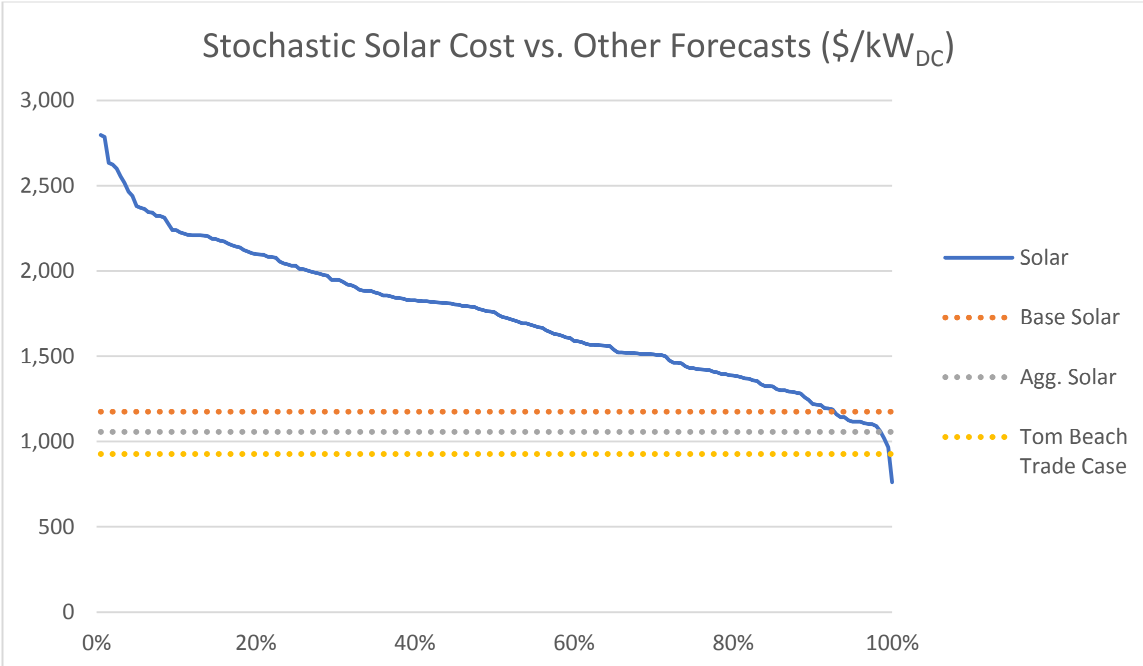


Figure 55 - Stochastic Solar Cost vs. Other Forecasts

Q. WHAT IS YOUR OPINION OF THE CAPITAL COSTS AS USED IN THE STOCHASTIC ANALYSIS?

A. They are incompatible with any reasonable expectation of the future. The median 2023 solar price used in the stochastic analysis is \$1,759/kW$_{DC}$. This is not only nearly double Mr. Beach's 2022 figure, it is substantially higher than costs of projects being installed today. The Lazard LCOE report referenced earlier shows prices for fixed-tilt systems installed today at \$917/ kW$_{DC}$. Even DTE's flawed cost projections show prices falling between now and 2025, so to suggest that the average system cost will somehow *increase* by 92% between now and 2023 is simply unreasonable.

The Outcome of DTE's Economic Risk Calculation Has Almost No Chance of Actually Happening

Q. PLEASE DISCUSS YOUR CONCERNS WITH THE ECONOMIC RISK CALCULATION.

A. PACE defined the Economic Risk as the average of the top 10% (20 in total) of cost runs for each variable when these variables were independently sorted. While the independent sorting breaks the apples-to-apples comparison for a given set of inputs, the iterations that appear in the 20 highest cost runs of each portfolio are largely consistent. That said, defining the Economic Risk without providing any context for how likely those outcomes are can be misleading. After analyzing the data from the Stochastic Analysis, I determined that the top 20 highest costs runs had a similar feature – they were all exceedingly unlikely to occur based on the expected values of the input variables.

Q. PLEASE DISCUSS THE RELATIVE IMPORTANCE OF THE 12 INPUT VARIABLES USED IN THE STOCHASTIC ANALYSIS.

A. In a data request, DTE supplied a set of scatter plots that plotted the total cost of each portfolio against the annual average input value. Many of these plots were fairly indistinct blobs, lacking any obvious correlation between the input variable and the total cost. But a few appear to have a more defined relationship. (ELPCDE 6.1h.)

As suggested by data provided in ELPCDE 6.1h, I performed a linear regression on the total cost of each portfolios to analyze the influence of individual variables on the Total Cost result. Due to the quantity of data, the input values were condensed by DTE into a single average value for each input for each of the 200 runs. While this is a fairly dramatic simplification, there is still enough variability in the input values to produce a wide range of averages. For instance, the Henry Hub average price ranges from $1.91/MMBTU to $8.19/MMBTU, and MISO Zone 7 peak load ranges from 16,290 MW to 34,181 MW.

Of the 12 input variables that were used, only four were determined to be statistically significant in any portfolio, and the same four variables were statistically significant in each portfolio. These were Henry Hub (i.e. natural gas prices), CO2 prices, LRZ7-MECS Load (average load, a proxy for sales), and LRZ7-MECS Peak (peak demand). The results for the NGCC portfolio regression are shown below in Figure 56.[90]

CC								
Regression Statistics								
Multiple R	0.935946938							
R Square	0.875996671							
Adjusted R Square	0.865887704							
Standard Error	6741703.29							
Observations	200							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	15	5.90781E+16	3.93854E+15	86.65540851	6.7793E-75			
Residual	184	8.3629E+15	4.54506E+13					
Total	199	6.7441E+16						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	-124,575,377	9,886,909	-12.600	0.000	-144,081,661	-105,069,093	-144,081,661	-105,069,093
Henry Hub	6,739,741	538,393	12.518	0.000	5,677,525	7,801,958	5,677,525	7,801,958
USA CO2	968,380	171,480	5.647	0.000	630,060	1,306,700	630,060	1,306,700
SO2 Zone 2	-8,453	9,658	-0.875	0.383	-27,509	10,602	-27,509	10,602
NOX (Both)	-1,420	3,097	-0.459	0.647	-7,531	4,691	-7,531	4,691
WTI	-45,719	49,895	-0.916	0.361	-144,158	52,720	-144,158	52,720
GasCC Capex	1,823	3,650	0.499	0.618	-5,379	9,025	-5,379	9,025
GasCT Capex	-6,572	4,489	-1.464	0.145	-15,429	2,286	-15,429	2,286
Solar Capex	1,773	2,318	0.765	0.445	-2,799	6,345	-2,799	6,345
Wind Capex	215	1,554	0.138	0.890	-2,851	3,281	-2,851	3,281
LRZ7-MECS Load	27,567	2,364	11.663	0.000	22,904	32,231	22,904	32,231
LRZ7-MECS Peak	-8,139	1,108	-7.344	0.000	-10,325	-5,952	-10,325	-5,952
CAPP Prices	-488,933	1,047,918	-0.467	0.641	-2,556,412	1,578,546	-2,556,412	1,578,546
NAPP Prices	-850,201	979,211	-0.868	0.386	-2,782,127	1,081,725	-2,782,127	1,081,725
ILB Prices	1,877,698	2,237,297	0.839	0.402	-2,536,357	6,291,752	-2,536,357	6,291,752
PRB Prices	-3,695,622	2,786,264	-1.326	0.186	-9,192,756	1,801,512	-9,192,756	1,801,512

Figure 56 - NGCC Stochastic Analysis Regression Results

Intuitively, it makes sense that these four variables would drive the Total Cost, but on first blush it was surprising that none of the capital cost or criteria pollutant cost variables were statistically significant. However, upon further inspection of the stochastic analysis, this made sense. The total cost value in the stochastic analysis is dominated by the production costs, that is, the cost of generating energy. Capital costs on average only make up 12.5% of the total NPV for the average run in the stochastic analysis. Given that 7/8 of the cost is from production, natural gas prices, CO2 prices, and load are the most logical suspects for driving total costs. Likewise, the model runs

[90] Regression results for the other portfolios are in my workpapers.

retire a significant amount of coal capacity, reducing the impact of SO2 and NOX compliances costs. Additionally, the Monroe coal plant that continues to run longer has already invested in emission reduction equipment, reducing exposure to these costs.

Q. DID YOU INVESTIGATE THE FOUR STATISTICALLY SIGNIFICANT VARIABLES FURTHER?

A. Yes. I produced a distribution of the values of each of these variables to try to understand how often they occurred in the modeling runs. Three of the four variables (natural gas prices, load, and peak demand) were distributed in a manner similar to the normal distribution. This was somewhat expected as the inputs for these values in the Monte Carlo simulation were based on normal distributions. The CO2 price was a bit different, with distinct peaks around $2.00/ton and again at $7.00/ton. This could be reflective of the different methodology that PACE used given there was no history of national CO2 prices to rely on.

The charts below in Figure 57 show a distribution built from a histogram, along with the distribution based on the input value's average and standard deviation. For Henry Hub, LRZ7-MECS Peak, LRZ7-MECS Load, a normal distribution was used. For the CO2 price, a gamma distribution was created that best matched the plot, although its fit is less robust than the other values. The histogram-based distribution is in blue, with the normal or gamma distribution in red. The left axis represents the count of the 200 runs that falls into the histogram bucket, while the right axis is the unadjusted distribution result. While the normal distribution fits are not perfect, they are reasonable approximations, particularly on the right tail where values are higher. The CO2 score was the most difficult to fit, but the Gamma distribution fit is directionally consistent with the underlying histogram data.

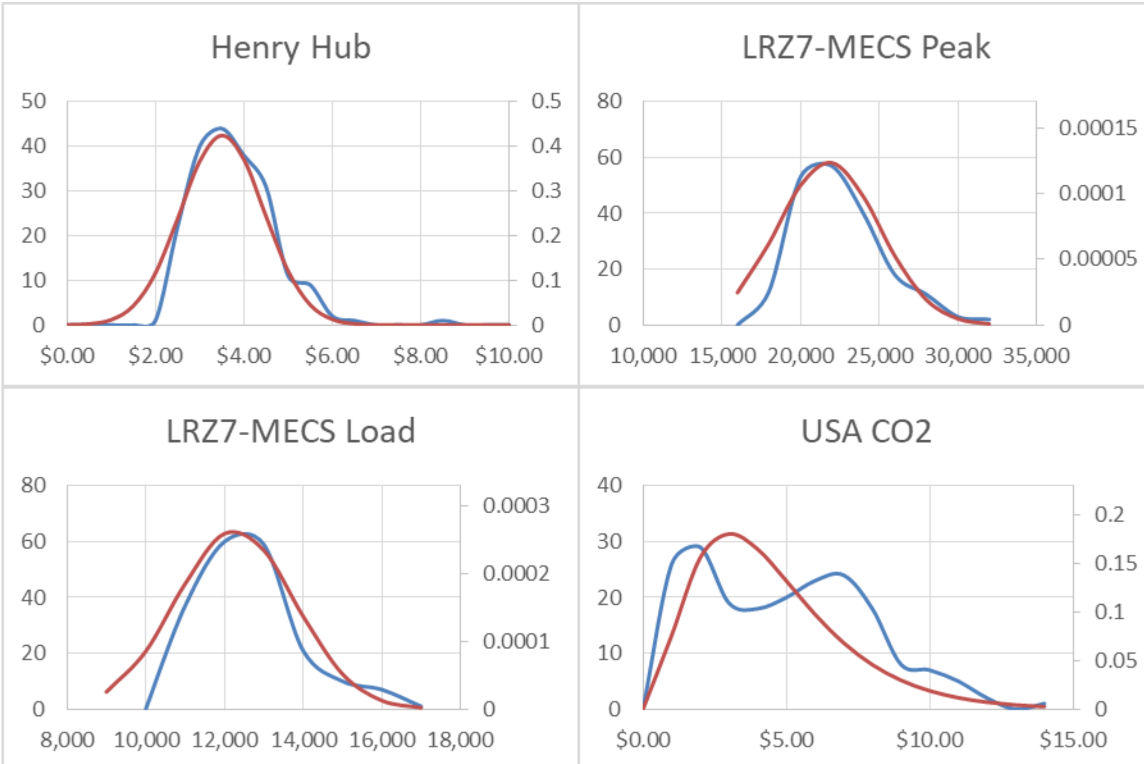


Figure 57 - Key Input Distributions

Q. ONCE YOU APPROXIMATED THE DISTRIBUTION OF THE INPUT VARIABLES, WHAT WAS THE NEXT STEP IN YOUR ANALYSIS?

A. The next step is to determine how likely a particular combination of inputs is given the distribution of each variable. The benefit of the normal and gamma distributions is that one can determine how likely it is for a given value to occur. I analyzed each of the four key variables in each of the runs to calculate the likelihood that a value equal or greater to the one in the run occurs. Next, I multiplied these numbers together to determine the chance of each value occurring in combination with the other values. As expected, the 20 most expensive runs had either a single input with an extremely high value, or a combination of unlikely values that combined to create a very unlikely combination.

For instance, the top 5 most expensive portfolios all had very high load and peak values. These five had an average load of 17,880 MW (probability = 0.01%) and an average peak load of 32,577 MW (probability = 0.04%). One can see how unlikely these values are to occur based on the expected distribution of loads and peaks in Figure 57 above. The 9th most expensive portfolio had a combination of low likelihood inputs, with a Henry Hub price of $5.38 (probability = 2.4%) and a CO2 price of $10.38 (probability of 3.2%), along with load and peak values with a 6.7% and 6.6% probability, respectively. When these probabilities are combined, they result in a very unlikely combination.

Q. HOW LIKELY ARE THE COMBINATIONS OF KEY INPUT VARIABLES THAT MAKE UP THE 20 MOST EXPENSIVE RUNS?

A. The odds of these portfolios occurring are vanishingly remote. The product of the four variable's probabilities were plotted against the average Total Cost for the four portfolios. As seen below in Figure 58, all of the Top 20 most expensive portfolios result from an extremely unlikely combination of inputs. In fact, on this chart, it is difficult to distinguish the combined probabilities from zero.

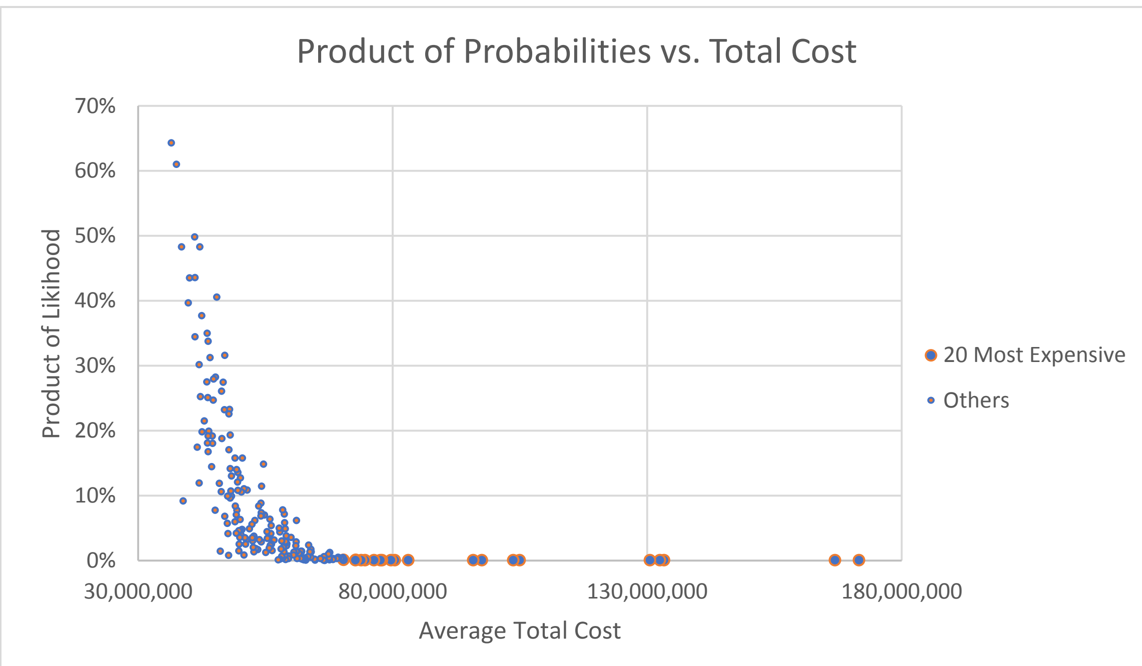


Figure 58 - Product of Probabilities vs. Total Cost

Figure 59 recasts the data using a logarithmic scale for the left axis. This does not change the results, but allows one to view just how incredibly small the combined likelihood of the input variables occurring in the top 20 most expensive runs actually is. Of the 20 most expensive runs, the most likely combination of key input variables would be expected to occur just 0.07% of the time. The least likely would be expected to occur 0.00000011% of the time, or roughly one out time out 930 million. The geometric mean[91] of the likelihood of all of the 20 most expensive portfolios happening is equivalent to 1:220,000. Even if one assumes that peak load and total sales are perfectly correlated (which they are not), the geometric mean of the likelihood of all of the 20 most expensive portfolios based on natural gas prices, CO2 prices, and peak load alone falls to 1:2,565.

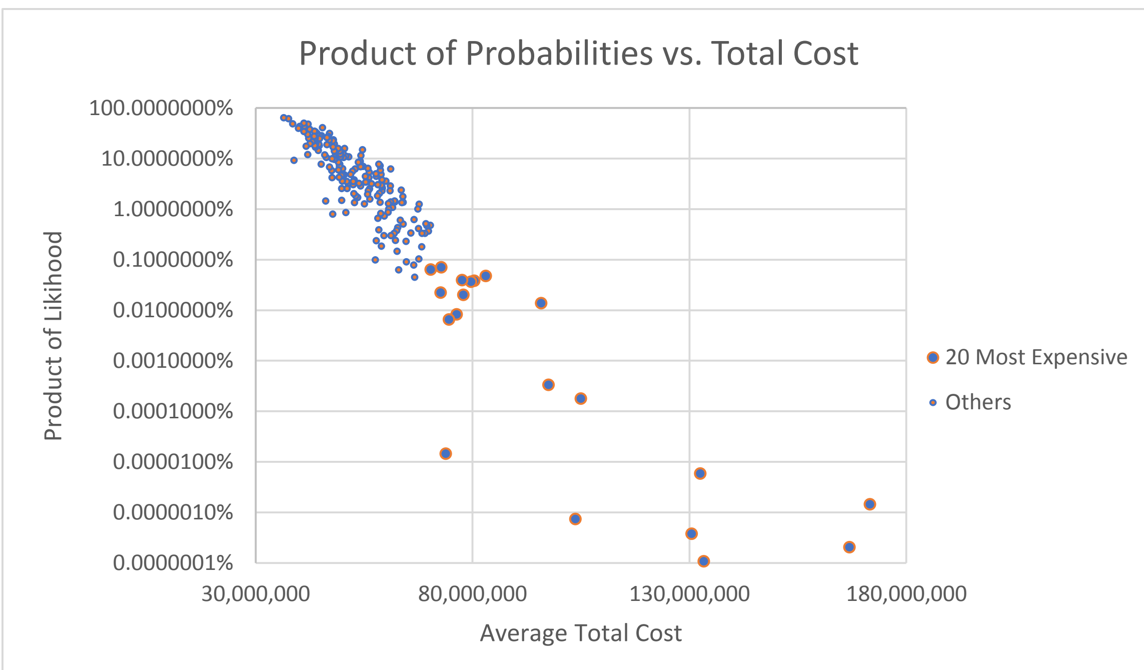


Figure 59 - Product of Probabilities vs. Total Cost - Log Scale

[91] The geometric mean is used given the widely disparate scale of the results.

Q. WHAT CAN YOU CONCLUDE FROM YOUR ANALYSIS OF THE STOCHASTIC RISK ASSESSMENT?

A. The Stochastic Risk Analysis does not provide meaningful insight into the performance of the various alternative portfolios. Setting aside my many concerns about how the three alternative portfolios were constructed, the failure of DTE to analyze more than just the Total Cost metric under the Reference case inputs limits the applicability of the results to just 11.7% of the total IRP characteristics that DTE deems important to analyze.

Further, presenting the results based on the average of most expensive 20 runs without a corresponding analysis of the probability of these runs occurring under the parameters of the analysis is misleading. As demonstrated above, the chances of some of these outlier portfolios occurring is vanishingly remote. As a group, the geometric mean, a proxy for the average likelihood of any of these 20 portfolios occurring, is roughly 1 in 220,000. Even assuming a perfect correlation between peak load and total sales, the odds only “improve” to 1:2,565. Given the extreme unlikelihood of these portfolios occurring, drawing conclusions related to average of the Total Cost of these runs provides no insight.

Q. PUT TOGETHER, DO DTE'S RISK ANALYSES DEFINITIVELY POINT TO ITS OWN PROPOSAL AS THE MOST PRUDENT COURSE OF ACTION?

A. No. In fact, DTE has done very little to demonstrate any meaningful risk analysis of its Proposed Project at all. The AHP analysis is flawed and should be discarded entirely. The Stochastic analysis at best presents an analysis of an incredibly unlikely set of circumstances that would apply to only a small fraction of relevant IRP factors. Far from proving its Proposed Project as the most reasonable alternative, the 2017 Scenario locks DTE in to a path that will reduce its options to meet its long-term CO2 reduction goals and potentially expose its customers to the costs of stranded assets.

Instead of bolstering its argument in favor of its Proposed Project, DTE's risk analyses suggest that other options, such as the alternative scenario described by expert witness Mr. Beach should be evaluated.

VI. <u>THE PROPOSAL PUT FORTH BY MR. THOMAS BEACH DEMONSTRATES THAT OTHER REASONABLE AND PRUDENT OPTIONS EXIST TO MEET DTE'S NEEDS AND THAT DTE FAILED TO ADEQUATELY CONSIDER THEM.</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE TOPICS YOU WILL DISCUSS IN THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the analytical results of the proposal put forth by Mr. Thomas Beach. I contrast Mr. Beach's assumptions with DTE's, and review Mr. Beach's conclusion that an alternative portfolio of distributed resources can meet DTE's energy and capacity obligations at a lower price than the Proposed Plan. I also discuss ways in which Mr. Beach's assumptions are conservative, highlighting recent successes from other states in areas such as energy efficiency and demand response as well as discussing a shift away from large, centralized resources to meet future energy needs.

Overview and Results of Mr. Beach's Alternative Portfolio

Q. PLEASE SUMMARIZE YOUR TESTIMONY TO THIS POINT THAT IS RELEVANT TO MR. BEACH'S TESTIMONY.

A. DTE flatly rejects the notion that a portfolio of distributed renewable resources can be used to meet its definition of reliability, but this conclusion is based on a logical fallacy. DTE's definition of reliability, as expressed through the requirement that a plant be dispatchable, conflicts with MISO's definition. And given that MISO is the entity that enforces the rules for the reliable operation of the bulk power grid, DTE's definition is not relevant. Simply put, DTE can meet MISO's resource adequacy requirements – the real goal of obtaining capacity resources – through other means than the Proposed Project, but it never considered solutions outside its incorrect construct of what a reliable plant is and is not.

Additionally, DTE systematically made assumptions and decisions that reduced the performance of alternatives in its IRP modeling. Its renewable energy price forecasts were overly simplistic and higher than current projections from market-leading sources. Its deployment forecasts were woefully low, ignoring any increase in DG solar in most scenarios, foregoing the possibility of an increase from PURPA projects, and generally failing to install renewables in a manner that would maximize the benefit of federal tax credits. DTE's failure to use the energy efficiency scenario that maximized customer benefits is inexplicable, and its choice to reduce demand response assumptions in its 2017 update essentially "gives up" on a promising program after one year of data.

DTE's failure to examine a portfolio that contains more energy efficiency and demand response along with larger and earlier deployments of wind and solar results from its erroneous understanding of what a reliable resource is. DTE is seeking a CON that affirms that "the size, fuel type, and other design characteristics of the Proposed Project represents the most reasonable and prudent means of meeting that power need (Section 6s(3)(b))." (Dimitry Direct at 11.) Given that DTE discarded any means of meeting this power need that did not comport to its flawed definition of reliability, I do not believe that it has met its requirement for this CON.

Q. IF DTE HAD NOT BEEN PREJUDICED AGAINST A PORTFOLIO OF DISTRIBUTED RESOURCES TO MEET ITS CAPACITY NEEDS, WHAT TYPE OF PORTFOLIO SHOULD IT HAVE ANALYZED?

A. It should have analyzed something very similar to the one presented by Mr. Beach. His portfolio addresses all of the issues I discussed above. It includes higher assumptions on energy efficiency and demand response, and builds more wind and solar earlier in the timeline. Combined, these actions are able to meet the projected capacity shortfall that was the genesis of the need in this CON.

Q. PLEASE DESCRIBE MR. BEACH'S PORTFOLIO.

A. Mr. Beach's portfolio is summarized below:

- 1,100 MW (nameplate) of new solar generation, including:
    - 200 MW of distributed solar
    - 300 MW of utility-scale fixed-tilt systems
    - 600 MW of utility-scale tracking arrays
- 1,100 MW (nameplate) of new wind projects
- Increase EE target of 2.0% load reductions per year, from DTE's planned 1.5%.
- Add 253 MW of incremental demand response capacity by 2023, based on 50% of the Realistic Low potential in the new State of Michigan DR Potential Study.

Figure 60 below compares Mr. Beach's solar (blue) and wind (orange) renewable energy deployment in MW_{AC} with three DTE deployment assumptions. The DTE reference cases do not attempt to build capacity for reliability purposes, but rather to meet the generation needs of the RPS. The High Renewables case assumes more builds than the reference cases, but most occur after the Proposed Project is in place. By contrast, only Mr. Beach's portfolio utilizes solar and wind capacity as a major component of meeting DTE's resource adequacy requirements.

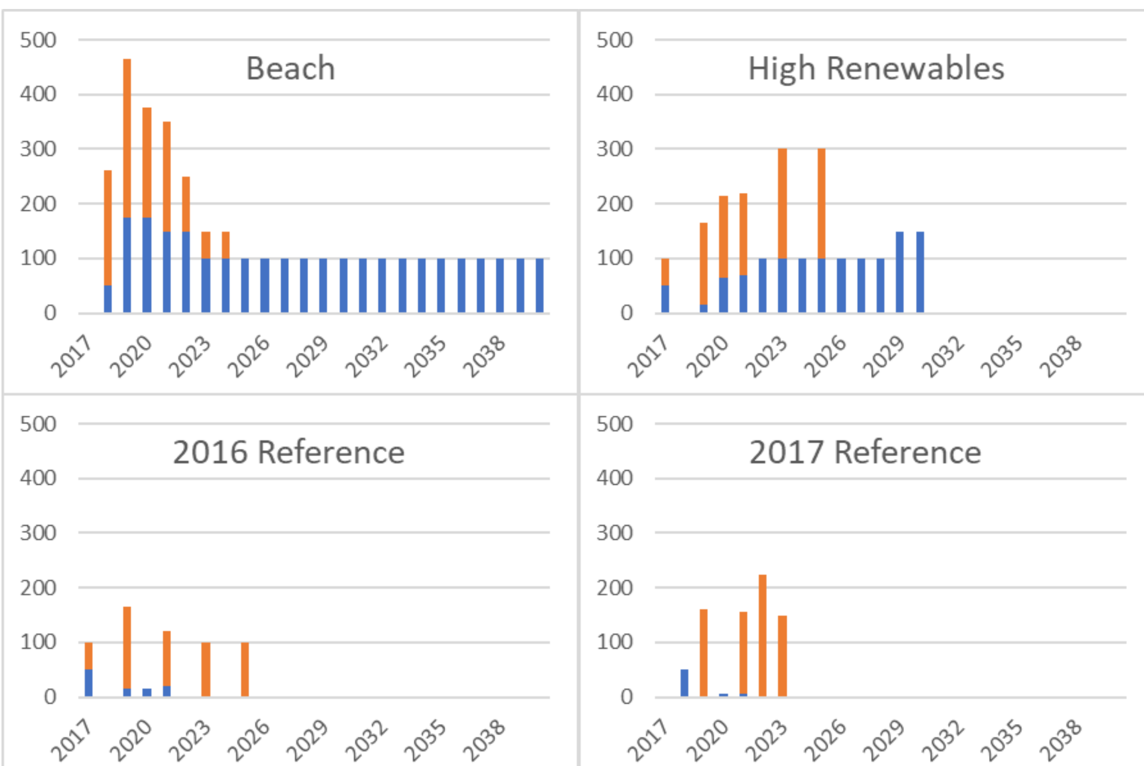


Figure 60 - Renewable Energy Portfolio Comparison

While all of DTE's solar is assumed to be south-facing, fixed-tilt installations, Mr. Beach divides up his portfolio further. He assumes 200 MW of distributed generation solar, 300 MW of utility-scale fixed-tilt systems, and 600 MW of utility-scale single-axis tracker systems. Using a similar modeling methodology as I discussed earlier in my testimony, Mr. Beach assumes a 49% and 63% capacity credit for fixed-tilt and single-axis tracking systems, respectively. He also assumes a 12.6% capacity credit for wind based on the latest MISO calculation for Zone 7.

In addition to the higher levels of renewable energy deployment, Mr. Beach increases the amount of assumed energy efficiency and demand response. He correctly utilizes the 2.0% energy efficiency portfolio based on the highest total net benefit to customers, although he does not attempt to correct DTE's inaccurate assumption that energy efficiency savings are "used up." Demand response capacity is conservatively assumed to capture 50% of the "Realistic Low" potential that was identified in the State of Michigan Demand Response Potential Study.[92]

Q. HOW DO EACH OF THESE RESOURCES CONTRIBUTE TOWARDS DTE'S RESOURCE ADEQUACY REQUIREMENT?

A. They each play a part, and this is one of the benefits of a portfolio of distributed resources. Unlike the Proposed Project, the capacity of Mr. Beach's portfolio is not all simultaneously at risk of failing to operate. The capacity contribution of each resource as calculated by Mr. Beach is shown below in Table 18, with the exception of the final MW_{UCAP} of the Proposed Project, which was taken from WP KJC-323.

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[92] See *State of Michigan Demand Response Potential Study*, released September 29, 2017. Available at http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406250--,00.html.

New renewable generation	**Nameplate (MW)**	**MISO RA Criteria (%)**	**RA Capacity (MW)**
Solar – fixed array	500	49%	242
Solar – tracking	600	63%	372
Wind	1,100	12.6%	139
Incremental load reductions	**Load reduction (MW)**	**Reserve Margin @ 4% (MW)**	**RA Capacity (MW)**
2% per year EE	90	4	94
Demand response	251	10	261
Portfolio Total (MW)			**1,107**
Gas plant			***1,067***

Table 18 - Beach Capacity Resource Summary

Q. HOW DOES THE COST OF MR. BEACH'S PORTFOLIO COMPARE TO THE PROPOSED PROJECT?

A. Mr. Beach calculates the NPV of the costs between 2018 and 2042 for building the capacity and providing the energy from his portfolio at $2.31 billion. Using the same methodology, he calculates the NPV of the Proposed Project at $2.65 billion. The portfolio of distributed resources meets the capacity and energy needs of DTE while reducing the costs by almost 13%.

Mr. Beach also calculates an updated cost of DTE's Proposed Project. By accounting for factors such as a revised Henry Hub forecast, fuel price volatility, and gas pipeline impacts, Mr. Beach determines that the cost of the Proposed Project is actually 47% more expensive than DTE reports. Using this figure, the cost of the Proposed Project becomes $3.90 billion, a full 69% higher than the distributed portfolio.

Q. WHAT IS YOUR GENERAL OPINION OF MR. BEACH'S INPUTS AND ASSUMPTIONS?

A. I think they are entirely reasonable, and if anything, conservative in nature. Regarding his renewable energy assumptions, I have already discussed in detail the cost assumptions for solar, the potential for solar deployment in Michigan, and the benefits of using single-axis trackers. Mr. Beach independently reached the same conclusion in terms of the capacity contribution of these systems, and uses MISO's current (and lower) Zone 7 capacity values for wind.

For his energy efficiency and demand response assumptions, DTE has already demonstrated that the 2.0% energy efficiency scenario is highly cost effective and produces the largest benefit for customers. While I have already discussed my concerns with DTE's assumptions on the availability of energy efficiency, Mr. Beach incorporates these flawed but ultimately conservative assumptions. Mr. Beach's demand response assumptions are not substantially higher than DTE's original values, and he considers more programs than does DTE.

Q. IN WHAT WAYS ARE MR. BEACH'S INPUTS AND ASSUMPTIONS CONSERVATIVE?

A. They are conservative in numerous ways.

- Develops 1,107 MW_{UCAP} of capacity, 3.7% more than the 1,067 MW_{UCAP} of the Proposed Project
- Uses higher-cost distributed generation for a portion of its solar buildout
- Assumes 300 MW of utility-scale fixed-tilt systems, despite performance advantage of single-axis trackers.
- Orients fixed-tilt systems south, despite performance advantage of orienting to the southwest.
- Bases incremental demand response on only 50% of the "Realistic Low" value from the State of Michigan Demand Response Potential Study.
- The state-wide potential study report that Mr. Beach references has lower values for the demand response potential than does the GDS Demand Response Potential Study that was commissioned specifically for DTE.
- Incorporates the highest-cost recommendation of the International Trade Commission in its price projections for solar.
- Utilizes DTE's flawed assumption on energy efficiency deployment as discussed previously.

Each of these assumptions shifts Mr. Beach's portfolio to be more expensive than it would otherwise be. While I have not quantified the impact of normalizing these assumptions, they suggest that the cost difference between his portfolio and the Proposed Project is more likely to be a minimum than a maximum.

Q. WHAT IS YOUR CONCLUSION ABOUT MR. BEACH'S PORTFOLIO?

A. On balance, I believe that Mr. Beach's portfolio represents the type of portfolio that DTE should have been analyzing in its IRP. By using better renewable energy pricing and deployment assumptions and taking advantage of low-cost resources such as energy efficiency and demand response, Mr. Beach has compiled a portfolio of distributed resources that is superior to the Proposed Project in terms of cost and risk. It, not the Proposed Project, represents the most reasonable and prudent means of meeting DTE's power need.

Examples from Other Jurisdictions that are Shifting Away from Centralized Generation Towards Distributed Assets

Q. DO YOU HAVE EXAMPLES FROM OTHER JURISDICTIONS THAT ARE CONSIDERING A PORTFOLIO OF DISTRIBUTED ASSETS TO MEET RESOURCE ADEQUACY NEEDS?

A. Yes. Several states are evolving past traditional solutions for capacity and seeking out distributed assets that provide similar capacity but with additional capability. Three recent examples include California, New York, and Colorado. Additionally, other states such as Maryland have rapidly developed robust energy efficiency and demand response programs that have enabled substantial reduction of peak demand, well beyond those assumed here.

Q. PLEASE DISCUSS SOME OF CALIFORNIA'S EFFORTS IN THIS AREA.

A. California has a suite of state policies driven by ambitious greenhouse gas reduction goals that are pushing the transformation of its power grid. It has very aggressive energy efficiency and renewable energy goals, and is working to electrify its transportation sector as well. As part of this transformation, California has embraced many distributed energy resource programs and policies that include both physical assets such as solar generation as well as behavioral programs such as rate design modifications.

Two near-term factors that will impact grid reliability are the retirement of the 2,160 MW Diablo Canyon nuclear facility and the replacement of the 262 MW Puente natural gas generating unit. Several years ago, Pacific Gas and Electric (PGE) reached an agreement with stakeholders to retire the aging nuclear facility rather than try to obtain an extension on its operating license.[93] As part of the agreement, the "Parties agree that the orderly replacement of Diablo Canyon with GHG free resources will be the reliable, flexible, and cost-effective solution for PG&E's customers."[94] These resources include a sizable increase in energy efficiency in the near-term, combined with higher renewable energy procurements and a higher voluntary RPS obligation in the medium- to long-term.

Another example relates to the replacement of the Puente natural gas facility. Initially, a California Independent System Operator (CAISO) study found that while a portfolio of distribution energy resources could serve the reliability needs of the area surrounding the facility, it would be much more expensive than a new natural gas plant. However, in a familiar refrain, it was subsequently determined that the CAISO study used very out-of-date cost assumptions on energy storage that rendered that alternative non-competitive.[95] This led several California Energy Commission members to recommend rejecting the proposed application, which in turn prompted the developer of the plant to suspend its application pending investigation into other preferred resources and energy storage alternatives.[96]

Q. PLEASE DISCUSS NEW YORK'S EFFORTS IN THIS AREA.

A. The state of New York is part way through its Reforming the Energy Vision (NY-REV) roadmap. NY-REV is less about addressing a single capacity need and more about

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[93] http://beta.latimes.com/business/la-fi-diablo-canyon-nuclear-20160621-snap-story.html
[94] Diablo Canyon Joint Proposal, available at https://www.pge.com/includes/docs/pdfs/safety/dcpp/JointProposal.pdf
[95] https://www.greentechmedia.com/articles/read/caiso-suggests-new-rfo-to-settle-question-of-storage-vs-puente-gas-plant
[96] https://www.greentechmedia.com/articles/read/nrg-suspension-puente-gas-plant-what-does-that-mean#gs.rSj8HT8

rethinking how the state will meet its energy needs in the future while reducing greenhouse gas emissions. At the core of this effort is energy efficiency and clean, locally produced power that will support the state's energy consumption and renewable energy goals. To this end, NY-REV aims to build a "clean, resilient, and affordable energy system for all New Yorkers."[97]

As part of this effort, stakeholders are addressing many factors that will affect how future capacity needs are met. This includes new valuation methodologies for distributed energy resources, updated rate designs to better align customer behavior with grid needs, "green bank" financing to provide capital to clean projects, and an innovative first-in-the-nation competition to help communities develop microgrids.[98] Combined, these programs and policies are aimed to replace traditional utility infrastructure upgrades that may be needed to meet future demands.

Q. PLEASE DISCUSS COLORADO'S EFFORTS IN THIS AREA.

A. In August 2017, Xcel Energy of Colorado reached an agreement with a diverse set of stakeholders to retire early two coal units with a capacity of 660 MW. At the same time, the company announced that it would solicit competitive requests for proposals for up to 1,000 MW of wind, up to 700 MW of solar, and up to 700 MW of natural gas and/or storage.[99]

The initial results of the competitive solicitation were just released. Xcel noted that "the response to this solicitation is unprecedented." Xcel received 17,380 MW of wind bids, and 13,435 MW of solar bids. The median price for projects (which will likely overstate the winning bid given that Xcel was only aiming for 1,000 MW of wind and 700 MW of solar) was $18.10/MWh for wind and $29.50/MWh for solar. Xcel also

[97] https://www.nyserda.ny.gov/-/media/Files/About/Clean-Energy-Fund/REV-Fact-Sheet.pdf
[98] Id.
[99] https://www.utilitydive.com/news/xcel-energy-proposes-shuttering-2-colorado-coal-plants/503878/

received 10,813 MW of solar plus storage bids, 5,097 MW of wind plus storage bids, and 1,614 MW of stand-alone storage bids. Astoundingly, the premium for solar plus storage was just $6.50/MWh over stand-alone solar projects, while the premium for storage plus wind projects was just $2.90/MWh over stand-alone wind projects.[100]

Q. PLEASE DISCUSS THE DEMAND RESPONSE PROGRAM IN THE STATE OF MARYLAND.

A. In 2008, Maryland passed the EmPOWER Maryland Energy Efficiency Act,[101] which set targets for utilities to reduce their per capita energy use and peak demand by 15% by 2015. While these targets were very aggressive when made, and the State was starting from scratch in terms of program experience, the utilities ultimately succeeded in hitting the peak demand reduction target and almost reached the energy use reduction target.

Demand response has been a particular bright spot for Maryland utilities. Initially, programs consisted of legacy direct control air conditioning switches, very similar to the program that DTE implements. Utilities began implementing smart thermostat-based systems that enabled customers to control the cycling of their air conditioner for different rebate amounts. After the implementation of advanced metering infrastructure, utilities began implementing behavioral and dynamic pricing programs. Currently, Maryland utilities offer a suite of programs that have helped reduce peak load in the state substantially.

At the same time, Maryland has implemented many energy efficiency programs, including lighting programs, appliance rebate programs, home performance, and a suite of prescriptive and customer commercial and industrial programs. While these programs have saved a tremendous amount of energy, they have also helped reduce peak demand.

[100] Id.
[101] http://mgaleg.maryland.gov/2008rs/chapters_noln/Ch_131_hb0374E.pdf

One particular utility, Baltimore Gas and Electric (BGE), reported that it has reduced 1,271 MW of peak demand through its various energy efficiency and demand response programs as of Q2 2017.[102] About 475 MW comes from energy efficiency programs, 390 MW from residential air condition demand response programs, and 394 MW through various behavioral and dynamic pricing programs.[103] BGE's 2016 peak demand was 6,601 MW,[104] so these demand reductions amount to about 16.1% of peak demand.

DTE's 2016 peak demand of 11,422 MW is about 73% higher than BGE's, as is its count of residential customers.[105] But despite having 73% more peak demand to reduce, and 73% more residential customers to implement energy efficiency and demand response programs, DTE only includes 80 MW from energy efficiency and 762 MW from demand response in its 2021 capacity calculation, for a total of 842 MW. On an apples-to-apples basis, this is only 38.3% of the demand reduction capability than BGE has obtained.[106] DTE can do better, and Mr. Beach's modest increase in demand response of 263 MW should be attainable.

Q. DO YOU HAVE ANY EXAMPLES OF NON-NUCLEAR LARGE, CENTRALIZED GENERATING PLANTS STRUGGLING IN THE RAPIDLY CHANGING ENERGY MARKET?

A. Yes. While the travails of the under-construction nuclear facilities in Georgia and South Carolina are well known, two recent examples underscore the risk that large, fossil-fueled centralized generators face today. The first involves a modern, new, efficient natural gas

[102] http://webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9100-9199\9154\\821.pdf
[103] Id, Appendix A, Program-to-Date, Gross Wholesale Reported Savings.
[104] Data from EIA Form 861, Operational_Data_2016.xlsx, Sales_Ult_Cust_2016.xlsx, utility number 1167 (BGE) and 5109 (DTE). Available at https://www.eia.gov/electricity/data/eia861/
[105] Id
[106] BGE savings grossed by 73% is 2,199 MW. 842 / 2,199 = 38.3%

power plant, very similar to the plant that DTE wants to build. Panda Temple Power LLC, which owns the 758 NGCC power plant in Texas, filed for bankruptcy earlier this year. Despite having commenced construction in 2012 and entering operation in 2014, only three years later, the plant was not able to meet its financial obligations based on its energy revenues.[107]

While Texas has a different regulatory regime than does Michigan, in areas where there is strong renewable energy potential and flat-to-declining load, even modern, efficient natural gas generators can be less cost-effective than alternatives. DTE would not have to go bankrupt if its Proposed Project went "out of the money," but its customers would be overpaying for the project's output.

A second example comes from neighboring Wisconsin. WEC Energy Group (WEC) recently announced that it was closing its Pleasant Prairie plant. This plant is about the same age as Belle River (which the company plans to operate until 2030) and 10 years younger than Monroe (which the company plans to operate until 2040). Reports indicate that the power plant has been operating at reduced capacities in recent years and did not operate for three months earlier this year. At the same time, WEC announced that it would develop 350 MW of new solar.[108]

While closing Pleasant Prairie will help reduce the carbon footprint of WEC, it will also retire a working asset that customers had paid for before the operational end of the plant. WEC spent $325 million in upgrades to this facility a decade ago, additional costs that are likely to be recovered from customers despite the plant's retirement. This risk of stranded assets caused by market changes and falling demand should be a cautionary tale for DTE's desire to build a new, large NGCC.

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[107] https://www.utilitydive.com/news/panda-temple-bankruptcy-could-chill-new-gas-plant-buildout-in-ercot-market/442582/

[108] https://www.jsonline.com/story/news/2017/11/28/we-energies-coal-fired-power-plant-pleasant-prairie-shut-down-2018/901891001/

Q. WHY DO YOU BELIEVE THAT STATES ARE RECONSIDERING LARGE, CENTRALIZED POWER PLANTS IN FAVOR OF MORE DISTRIBUTED, ZERO-CARBON RESOURCES?

A. I believe there are two main drivers to this trend. First, distributed, zero-carbon resources such as solar, wind, energy efficiency, and demand response have no fuel costs. Sun and wind are free, and the cost of reducing energy use does not depend on the cost of natural gas or coal. This is a major benefit for customers in both vertically integrated and restructured states. Because there are no fuel costs, and very little O&M costs, solar and wind projects can lock in 20 or 25 years of guaranteed price stability.

On the contrary, fixing natural gas prices more than a few years out is either expensive or impossible.[109] If DTE were not to hedge against future price changes, its customers could be faced with much higher gas prices in the future. However, this hedge costs money. Mr. Beach calculated the impact of this price risk for the Proposed Project as an additional $17/MWh or $86 million per year. This change alone increased his calculated cost of the Proposed Project by 25%.

The second is that the needs of the power grid are evolving. As states and utilities seek to reduce the carbon intensity of the power grid, more and more zero-carbon resources such as solar and wind are being built. While these resources do not produce carbon, they are intermittent in their generation. Of course, over a large geographic area such as Michigan, this intermittency is smoothed out, much like the load fluctuations of thousands of customers turning on and off their air conditioners are smoothed out. The intermittency of a single facility becomes much less important, and the total portfolio generation can be forecasted with increasing degrees of accuracy.

[109] See for instance future contracts for natural gas at http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html . Volumes for contracts between 2 and 10 years as basically nonexistent, and 10 years contracts are the longest duration available.

So while intermittency is not itself a major problem, the seasonal and diurnal variation in power generation from wind and solar alter what traditionally has been thought of as desirable characteristics of conventional generation. "Baseload" power is not useful when solar generation pushes down mid-day net loads below historic annual minimum loads. Rather, ramping capability is far more important in a high solar and wind world than is constant, inflexible output. Additionally, utilities and grid operators have learned the value of depending on demand-side resources to help shape and balance load to meet available demand.

If one takes as given a desire to dramatically reduce carbon emissions from the electricity sector, then one must necessarily plan for a future where flexibility is king. The Proposed Project as DTE imagines it does not provide this operation flexibility, and DTE did not consider battery technology to help meet its peak demand needs. As mentioned previously, DTE might be building capacity, but it is not building capability.

Q. GIVEN THE LOWER COST AND LOWER RISK OF A DISTRIBUTED PORTFOLIO, DO YOU BELIEVE THAT DTE'S PROPOSED PLAN IS THE MOST REASONABLE AND PRUDENT MEANS OF MEETING ITS POWER NEEDS?

A. No. Given that it did not even consider a distributed portfolio in its IRP, despite the clear trends in the energy industry and the cost and risk benefits demonstrated by Mr. Beach, it is not possible to conclude that DTE has done sufficient due diligence to find its Proposed Plan the most reasonable and prudent means to meet its identified power needs.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS

A. DTE has failed to meet its obligation in this proceeding to demonstrate that the Proposed Plan is the most reasonable and prudent means to meet its identified power needs. At every step of its IRP, DTE made choices and incorporated assumptions that inappropriately steered its modeling towards the company's desired outcome – the Proposed Project – while overlooking alternative solutions that could provide the needed level of resource adequacy in a less expensive, cleaner, and less risky manner.

DTE incorrectly dismisses the ability of a distributed portfolio to meet its resource adequacy requirements, leading it to leave out more reasonable alternative portfolios in its modeling exercise. Its focus on generating dispatchable power rather than meeting MISO's resource adequacy requirements is a crucial early mistake from which it cannot and does not recover.

DTE's renewable energy cost forecasts are consistently too high, and its deployment assumptions too low. It completely ignores the potential increase in PURPA projects, and in fact assumes that all existing PPAs will expire, not to be replaced. DTE models only the least effective system design and orientation (south-facing, fixed-tilt systems) while ignoring the fact that the industry has moved on to single-axis tracking systems due to their major improvements in energy and capacity production. Finally, it fails to take advantage of expiring federal tax credits that could greatly reduce the near-term costs of deployment solar and wind for its customers.

DTE's energy efficiency and demand response assumptions are also inadequate. Despite commissioning potential studies that demonstrate the vast quantity of cost-effective energy efficiency and demand response potential, DTE shortchanges its customers by failing to choose the efficiency portfolio that delivers the most benefit and making no effort to improve and expand its demand response portfolio. Its incorporation of energy efficiency in the base load forecast is convoluted at best, and falsely assumes that energy efficiency can simply "run out" while simultaneously taking no steps to address program design changes that can continue to produce more savings.

In its 2017 IRP update, DTE refreshes most of the major inputs to its modeling. Fuel prices, demand-side management assumptions, capital costs for the Proposed Project, load forecasts, and CO2 price assumptions are all updated. However, capital costs for solar and wind are inexplicably not. These changes significantly impact the NPVRR of the Proposed Plan, reducing it by nearly 15%. Despite this major shift in the underlying variables, DTE performed only a cursory refresh of its main IRP scenarios, relying instead on older and more out-of-date information.

DTE did develop a new 2017 75% CO2 reduction by 2040 scenario to attempt to demonstrate a path towards its long-term corporate CO2 reduction goals. However, when the operating assumptions of the CO2 reduction scenario are examined more closely, DTE has not demonstrated a viable path towards its goals even if it is able to extend the Fermi nuclear plant. And if Fermi's operating life is not cost-effective to extend, there is little hope that its plan of three baseload NGCC will be compatible with its CO2 goals.

One of the most important financial analyses that DTE presents in its IRP – a comparison of costs between the Proposed Plan and a No Build scenario – is flawed in multiple ways. By its own admission, DTE compares its project to a scenario that it does not deem reasonable or prudent, but it is the only comparison offered. Additionally, the financial comparison it does present uses questionable capacity cost assumptions, and more critically, derives a substantial portion of the total reported benefits from a second NGCC and CO2 compliance costs that are completely out of scope in this proceeding. Rather than immediately adding value to customers as DTE suggests, the Proposed Project saddles DTE customers with hundreds of millions of dollars before it starts to pay anything back.

Moving away from the internal assumptions and presentation of the IRP results, I find that DTE's Proposed Plan substantially understates the risk to its customers. Rather than optimizing its portfolio through zero-carbon, fixed-price wind and solar projects and expanding highly cost-effective energy efficiency and demand response portfolios, DTE pulls up short in these areas. Its misguided focus on "dispatchable" energy causes it to overlook less expensive, lower risk assets that can meet its resource adequacy obligations to the detriment of its customers. DTE compounds this mistake by adding a second NGCC in its modeling, locking in inflexible generation just as the need to incorporate increasing penetrations of wind and solar will demand more flexibility from its assets.

DTE's own risk analysis is sorely lacking. Its two quantitative analyses both suffer from flaws that require the conclusions be given no weight. The AHP analysis suffers from numerous procedural and methodological problems, from the use of only in-house SMEs, to the lack of scale-dependency that makes saving $1 as useful as saving $100 million, to the ultimate brittleness of its results under any real-world uncertainty. The Stochastic analysis offers at best a snapshot on one small aspect of the Proposed Plan, but the odds that the input variables would actually produce the results of the analysis are *de minimus*.

Finally, DTE's failure to investigate viable alternatives led it to miss the opportunity to explore a distributed portfolio similar to the one presented by Mr. Beach. In his analysis, Mr. Beach demonstrates how a diversified portfolio of solar, wind, energy efficiency, and demand response assets can exceed DTE's resource adequacy requirements at a lower cost and with less risk than the Proposed Project.

Despite all its false choices and bad assumptions, and despite its failure to present the IRP results or perform a risk analysis in a meaningful manner, this final oversight ultimately demonstrates that DTE did not sufficiently consider other reasonable and prudent alternatives to meet is power needs. As such, its CON should be denied.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

EXHIBITS OF

KEVIN LUCAS

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

MPSC Case No.: U-18438
Respondent: R. J. Mueller
Requestor: ELPC
Question No.: ELPCDE-11.19
Page: 1 of 1

Question: Please provide all correspondence with interconnection applicants that refers or relates to DTE's capacity needs over the next ten years.

Answer: DTE sent the below form letter text to the following recipients on 12/21/2017

Cypress Creek: MI.Utility@ccrenew.com
Orion: Andrew Makee amakee@orionrenewables.com
Geronimo: csiebenshuh@geronimoenergy.com; 'Tena Monson' tena@geronimoenergy.com
SPower: 'Daniel Wang' dwang@spower.com
NET Sun: Adam Schumaker <aschumaker@gmail.com>

PURPA Qualifying Facility Notification

This letter is to inform you that if you intend your project to be a PURPA Qualifying Facility, please see DTE Electric Rider No. 6 and note that Standard Offers are for projects less than 100kW. Consistent with the current Company tariff, the terms and conditions for a Power Purchase Agreement (PPA) for any facility greater than 100kW would be negotiated. Furthermore, any PPA that we negotiate in connection with a PURPA qualifying facility will be negotiated consistent with all PURPA rules, including the one-mile rule. The Company presently forecasts that it has no additional capacity needs in the next 10 years.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-9.2b
Page: 1 of 1

Question: Refer to Exhibit A4 2nd Revised at 74-75.

b) Did DTE explicitly assume any new PURPA capacity will be constructed in its IRP? If so, please indicate what scenario/sensitivity this assumption was found in, and what workpapers support this figure.

Answer: The Company did not include any specific PURPA projects in the 2017 IRP plan. However, as discussed starting on page 36 of my testimony, “I discussed the setting of the 300 MW purchase limit earlier in Section III of my testimony. Even though the modeling assumes that the amount would be filled by market purchases, DTE considers it an open position that can be filled by smaller economic resources determined at a later date. These resources could consist of a portfolio of renewables, CHP, DG, or demand response options in addition to market purchases.” In addition, the low load sensitivity would encompass a potential net effect increased PURPA capacity would have on the demand for utility capacity and energy.

MPSC Case No.: U-18419
Respondent: W. H. Damon
Requestor: ELPC
Question No.: ELPCDE-3.12b
Page: 1 of 1

Question: Please provide any supporting data for Mr. Damon's assertion on page WHD-15 that "[c]ombined cycle power plants are amongst the most reliable forms of utility scale power generation technologies."

b. Please explain why a single 1,100 MW combined cycle plant at a single location is more reliable than a diverse fleet of smaller utility-scale renewable power plants that are geographically distributed over a utility's service territory.

Answer: Reliability encompasses measure of the ability of a generating unit to perform its intended function, which is to supply energy to the grid when dispatched. Renewable plants are not dispatchable, and as such do not represent a direct comparison to a central 1100 MW combined cycle plant. For renewable capacity to be considered "reliable," additional firming capacity assets (generally natural gas engines, combustion turbines or extended battery) need to be installed.

MPSC Case No.: U-18419
Respondent: W. H. Damon
Requestor: ELPC
Question No.: ELPCDE-7.4f
Page: 1 of 1

Question: Refer to ELPCDE-3.12b.

f) What type of event would be required to cause a geographically distributed fleet of 550 2 MW UCAP distributed solar and wind systems to experience an outage that would render all 1,100 MW of capacity unavailable at the same time during MISO peak hours, which are typically summer weekdays between 2 and 5 PM?

Answer: A distributed fleet of 550 2 MW UCAP distributed solar and wind systems cannot meet the intended purpose of the Proposed Project as noted in the Company's answer to ELPCDE-3.12b.

MPSC Case No.: U-18419
Respondent: A. P. Wojtowicz
Requestor: ELPC
Question No.: ELPCDE-7.4b
Page: 1 of 1

Question: Refer to ELPCDE-3.12b.

b) Does MISO require "additional firming capacity assets (generally natural gas engines, combustion turbines or extended battery) need to be installed" in order to for solar or wind projects to receive a capacity credit based on MISO's approved capacity credit calculation methodology?

Answer: No.

MPSC Case No.: U-18419
Respondent: W. H. Damon
Requestor: ELPC
Question No.: ELPCDE-7.4d
Page: 1 of 1

Question: Refer to ELPCDE-3.12b.

d) Is it possible for a single, central 1,100 MW combined cycle plant to experience an outage that would cause the entire 1,100 MW of capacity to be unavailable at the same time, and that this type of outage may occur during MISO peak hours, which are typically summer weekdays between 2 and 5 PM?

Answer: Yes.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-7.4e
Page: 1 of 1

Question: Refer to ELPCDE-3.12b.

e) Please confirm that the anticipated unplanned outage rate for the Proposed Project is 3.78% per ELPCDE-3.13g, and that this translates into an expectation that the plant will be unexpectedly out of service for 331 hours or nearly 14 days a year. If the expected number of unplanned outage hours is any different, please indicate what the values is.

Answer: Confirmed. The ROR input in the model shows 5.78%, out of which 3.78% is the ROR portion and 2% is the periodic maintenance portion. 3.78% translates to 331 hours (or 14 days) of unplanned outage hours per year.

MPSC Case No.: U-18419
Respondent: W. H. Damon
Requestor: ELPC
Question No.: ELPCDE-7.4f Supplemental
Page: 1 of 1

Question: Refer to ELPCDE-3.12b.

f) What type of event would be required to cause a geographically distributed fleet of 550 2 MW UCAP distributed solar and wind systems to experience an outage that would render all 1,100 MW of capacity unavailable at the same time during MISO peak hours, which are typically summer weekdays between 2 and 5 PM?

Answer: A distributed fleet of 550 2 MW UCAP distributed solar and wind systems cannot meet the intended purpose of the Proposed Project as noted in the Company's answer to ELPCDE-3.12b.

Supplemental Response:

Generation capability of solar plants will be significantly impacted during the MISO peak hours by cloud cover or thunderstorms.

Similarly, generation capability of wind plants are variable and not predictable during the MISO peak hours when wind velocity may or may not be at the condition required to allow the wind turbine to operate at rated load capability. All 1,100 MW of wind turbine capacity could be rendered unavailable during calm winds when the turbines don't receive enough energy to operate. The wind turbines could also be rendered unavailable during extremely high winds that exceed the design characteristics of the turbine manufacturer forcing the turbines to pitch into the wind to prevent equipment failure.

MPSC Case No.: U-18419
Respondent: T. L. Schroeder/Legal
Requestor: ELPC
Question No.: ELPCDE-3.2u
Page: 1 of 1

Question: Refer to Exhibit A-4, the 2017 Integrated Resource Plan.

f. Please provide the "accompanying databook" mentioned on page 2 of the U.S. Distributed Renewables Deployment Forecast.

Answer: DTE Electric objects for the reason that the information requested consists of confidential, proprietary research and development of trade secrets or commercial information, the disclosure of which would cause DTE Electric and its customers competitive harm. Subject to this objection, and without waiver thereof, the Company would answer as follows:

The file ""ELPCDE-3.2u U. S. Distributed Renewables Deployment Forecast 2016 Data" is being supplied to parties that have signed a non-disclosure certificate subject to the protective order in this case.

MPSC Case No.: U-18419
Respondent: T. L. Schroeder
Requestor: ELPC
Question No.: ELPCDE-1.32
Page: 1 of 1

Question: Please provide the basis for DTE's assumed annual O&M cost for solar ($12/kW) that is shown on page TLS-13.

Answer: The O&M cost for solar of $12/kW was based on the December 2016 Lazard LCOE report, "Levelized Cost Energy Analysis 10.0."

MPSC Case No.: U-18419
Respondent: T. L. Schroeder
Requestor: ELPC
Question No.: ELPCDE-4.2c
Page: 1 of 1

Question: DTE response ELPCDE-1.32 indicates that the $12/kW value comes from the December 2016 Lazard LCOE report, "Levelized Cost Energy Analysis 10.0."

c. Given that DTE has modeled only fixed tilt designs, why did it use the $12/kW-year figure instead of the $9/kW-year figure?

Answer: The $12/kW-year estimate is a proxy for O&M in the absence of Michigan-specific, annualized, fixed-tilt utility-scale O&M cost data to reference.

MPSC Case No.: U-18419
Respondent: W. H. Damon
Requestor: ELPC
Question No.: ELPCDE-7.6b
Page: 1 of 1

Question: Please refer to Exhibit A-38 (HDR Report).

b) On page 99 of the HDR report, Table 5-17 shows a First Year Fixed O&M cost of $23,263/MW. For the 20 MW project, this amounts to $465,260. However, the only value provided in this section that might count towards this figure is the salaried staff position listed in part a) above. Please provide a detailed accounting of the expected $465,260 expense for the first year of operation of a 20 MW solar project.

Answer: IRP studies are intended to compare generation technologies to understand how these technologies may be employed to meet forecasted needs. The makeup of the first year fixed O&M cost of 23,263 $/MW includes 5,052 $/MW associated with personnel cost allocation discussed in (a) above, and 18,211 $/MW toward fixed O&M costs.

MPSC Case No.:	U-18419
Respondent:	K. J. Chreston
Requestor:	MECNRDCSC
Question No.:	MECNRDCSCDE-9.6a
Page:	1 of 1

Question: Refer to "U-18419 MECNRDCSCDE-5.2a KJC-48 relinked.xlsx.," tab "Solar," row 22. Refer also to Direct Testimony of T.L. Schroeder, p. TLS-13 at 4, and to DTE IPR, p. 125.

a. Confirm that DTE assumed solar O&M costs of $23/kW in KJC-48, and that this assumption was used for all new solar resource O&M costs input into Strategist. If not confirmed, provide an alternative explanation of the calculations performed in revised workpaper KJC-48.

Answer: Confirmed.

MPSC Case No.: U-18419
Respondent: M. B. Leuker
Requestor: ELPC
Question No.: ELPCDE-5.38
Page: 1 of 1

Question: Please provide a schedule of solar self-generation assumptions, including counts of systems, energy generation, and peak load reduction for the Reference, High Load, and Low Load forecasts.

Answer: The Reference Scenario and the High Load Sensitivity did not include solar self-generation in the forecast. For assumptions used in the Low Load Sensitivity and the 2017 Reference Case, please see the response to ELPCDE-3.2n. Counts of systems were not used in the assumptions. Peak load reduction was not explicitly determined for solar self-generation for any of the forecasts. However, in the Low Load Sensitivity and the 2017 Reference Case, the effect of solar self-generation was implicitly included in the peak demand forecast.

MPSC Case No.: U-18419
Respondent: M. B. Leuker
Requestor: ELPC
Question No.: ELPCDE-3.2n
Page: 1 of 1

Question: Refer to Exhibit A-4, the 2017 Integrated Resource Plan.

n. Please provide any studies, workpapers, or other documentation relevant to DTE's projections for distributed solar adoption.

Answer: In the Low Load Sensitivity, the Residential sales forecast includes a loss in sales of 3 GWh per year beginning in 2016 due to the adoption of photovoltaic systems.

In the 2017 Reference Case, the Residential sales forecast includes the adoption of photovoltaic systems. As photovoltaic systems are already included in historical data through 2016, the Residential model only included the incremental impacts of additional adoption of photovoltaic systems. The calculation utilized a capacity factor of 13.82%, which is DTE Electric's actual photovoltaic capacity factor for its SolarCurrents program in 2013. See the Excel file "U-18419 ELPCDE-3.2n Residential PV Calculation.xlsx" for the derivation of the incremental impacts of additional adoption of photovoltaic systems.

MPSC Case No.: U-18419
Respondent: M. B. Leuker
Requestor: ELPC
Question No.: ELPCDE-3.2n Supplemental
Page: 1 of 1

Question: Refer to Exhibit A-4, the 2017 Integrated Resource Plan.

a. Please provide any studies, workpapers, or other documentation relevant to DTE's projections for distributed solar adoption.

Answer: In the Low Load Sensitivity, the Residential sales forecast includes a loss in sales of 3 GWh per year beginning in 2016 due to the adoption of photovoltaic systems.

In the 2017 Reference Case, the Residential sales forecast includes the adoption of photovoltaic systems. As photovoltaic systems are already included in historical data through 2016, the Residential model only included the incremental impacts of additional adoption of photovoltaic systems. The calculation utilized a capacity factor of 13.82%, which is DTE Electric's actual photovoltaic capacity factor for its SolarCurrents program in 2013. See the Excel file "U-18419 ELPCDE-3.2n Residential PV Calculation.xlsx" for the derivation of the incremental impacts of additional adoption of photovoltaic systems.

Supplemental Response:
Attachment U-18419 ELPCDE-3.2n Residential PV Calculation.xlsx was inadvertently omitted from the transmittal of ELPCDE-3 1st Partial on November 29, 2017. The attachment is being supplied with this supplemental respons.

Case No.: U-18419

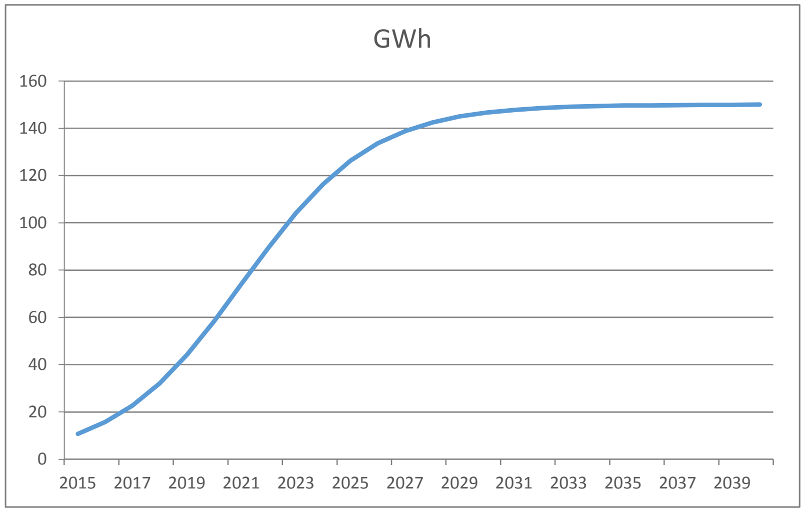
DTE Electric Company

Attachment: ELPCDE-3.2n

Respondent: M.B. Leuker

File Name: U-18419 ELPCDE-3.2n Residential PV

Year	GWh
2015	10.7
2016	15.7
2017	22.7
2018	32.2
2019	44.2
2020	58.4
2021	74.1
2022	89.8
2023	104.2
2024	116.5
2025	126.3
2026	133.6
2027	138.8
2028	142.5
2029	145.0
2030	146.7
2031	147.8
2032	148.6
2033	149.1
2034	149.4
2035	149.6
2036	149.7
2037	149.8
2038	149.9
2039	149.9
2040	150.0



HISTORICAL DATA

Year	Capacity (kW)	Cumulative Capacity (kW)	Lost Sales (GWh)
2006	27.7	27.7	0.0
2007	0.0	27.7	0.0
2008	57.5	85.2	0.1
2009	392.4	477.6	0.6
2010	2054.2	2531.8	3.1
2011	2374.8	4906.6	5.9
2012	562.1	5468.7	6.6
2013	988.4	6457.1	7.8
2014	1451.4	7908.4	9.6
2015	898.2	8806.6	10.7

MPSC Case No.: U-18419
Respondent: M. B. Leuker
Requestor: ELPC
Question No.: ELPCDE-3.2o
Page: 1 of 1

Question: Refer to Exhibit A-4, the 2017 Integrated Resource Plan.

o. Did DTE consider higher-than-expected DG solar adoption rates? If so, how would these accelerated adoption rates change DTE's anticipated capacity and energy needs over the planning horizon?

Answer: Please see the response to ELPCDE-3.2n for a description of distributed solar adoption included in the sales forecasts in the 2017 IRP. The capacity associated with solar adoption was not determined.

MPSC Case No.: U-18437
Respondent: R. J. Mueller
Requestor: ELPC
Question No.: ELPCDE-11.18a-d
Page: 1 of 5

Question: With respect to each of those interconnection applications, please provide:
a. The date the application was filed
b. The project technology (i.e. wind, solar, hydro, biomass, landfill gas, waste to energy, natural gas)
c. The project capacity
d. The status of the project application

Answer:

Project Number	Date Application Received	Applied For (KW)	KVA	Generation Type	Status
DE-01949	1/27/2016	5000	5000	Gas Turbine	Application
DE-01947	1/30/2016	672	672	Solar PV	Project Complete
DE-01950	3/29/2016	744	744	Solar PV	Project Complete
DE1670	5/4/2016	8000	8000	Gas Turbine	Engineering Study
DE-02101	5/24/2016	324	324	Solar PV	Project Complete
DE-02102	5/25/2016	300	300	Solar PV	Project Complete
DE-02103	5/26/2016	348	348	Solar PV	Project Complete
DE-02104	5/27/2016	240	240	Solar PV	Project Complete
DE-02023	10/28/2016	375	375	Solar PV	Application
DE-02044	12/2/2016	2200	2200	Gas Turbine	Engineering Study
DE17009	1/13/2017	3300	3300	Dynometer	Construction
DE-02161	2/24/2017	5000	5000	Solar PV	Application
DE-02162	2/24/2017	5000	5000	Solar PV	Application
DE-02163	2/24/2017	5000	5000	Solar PV	Application
DE-02164	2/24/2017	2000	2500	Solar PV	Engineering Study
DE-02165	2/24/2017	5000	5000	Solar PV	Application
DE17120	6/6/2017	20000	22500	Solar PV	Application
DE17121	6/6/2017	20000	22500	Solar PV	Application
DE17118	6/14/2017	8750	8750	Synchronous Gas	Engineering Study
DE17179	8/2/2017	2000	2200	Solar PV	Application
DE17180	8/2/2017	2000	2200	Solar PV	Application
DE17181	8/2/2017	2000	2200	Solar PV	Application

MPSC Case No.: U-18437
Respondent: R. J. Mueller
Requestor: ELPC
Question No.: ELPCDE-11.18a-d

Project Number	Date Application Received	Applied For (KW)	KVA	Generation Type	Status
DE17182	8/2/2017	2000	2200	Solar PV	Application
DE17187	8/4/2017	2000	2200	Solar PV	Application
DE-02384	8/16/2017	7700	7700	Gas Turbine	Application
DE-02390	8/17/2017	2000	2200	Solar PV	Application
DE-02391	8/17/2017	2000	2200	Solar PV	Engineering Study
DE-02392	8/17/2017	2000	2200	Solar PV	Application
DE-02393	8/17/2017	2000	2200	Solar PV	Application
DE-02394	8/17/2017	2000	2200	Solar PV	Engineering Study
DE-02395	8/17/2017	2000	2200	Solar PV	Application
DE-02396	8/17/2017	2000	2200	Solar PV	Application
DE-02397	8/17/2017	2000	2200	Solar PV	Application
DE-02398	8/17/2017	2000	2200	Solar PV	Application
DE-02399	8/17/2017	2000	2200	Solar PV	Application
DE-02400	8/17/2017	2000	2200	Solar PV	Application
DE-02401	8/17/2017	2000	2200	Solar PV	Application
DE-02402	8/17/2017	2000	2200	Solar PV	Application
DE-02403	8/17/2017	2000	2200	Solar PV	Application
DE-02404	8/17/2017	2000	2200	Solar PV	Application
DE-02405	8/17/2017	2000	2200	Solar PV	Application
DE-02406	8/17/2017	2000	2200	Solar PV	Application
DE-02425	8/23/2017	2000	2200	Solar PV	Application
DE-02426	8/23/2017	2000	2200	Solar PV	Application
DE-02427	8/23/2017	2000	2200	Solar PV	Application
DE-02428	8/23/2017	2000	2200	Solar PV	Application
DE-02429	8/23/2017	2000	2200	Solar PV	Application
DE-02430	8/23/2017	2000	2200	Solar PV	Application
DE-02431	8/23/2017	2000	2200	Solar PV	Application
DE-02432	8/23/2017	2000	2200	Solar PV	Application
DE-02433	8/23/2017	2000	2200	Solar PV	Engineering Study
DE-02434	8/23/2017	2000	2200	Solar PV	Application
DE-02435	8/23/2017	2000	2200	Solar PV	Application
DE-02436	8/23/2017	2000	2200	Solar PV	Application

MPSC Case No.: U-18437
Respondent: R. J. Mueller
Requestor: ELPC
Question No.: ELPCDE-11.18a-d
Page: 3 of 5

Project Number	Date Application Received	Applied For (KW)	KVA	Generation Type	Status
DE-02437	8/23/2017	2000	2200	Solar PV	Application
DE-02438	8/23/2017	2000	2200	Solar PV	Application
DE-02439	8/23/2017	2000	2200	Solar PV	Engineering Study
DE-02447	8/28/2017	2000	2200	Solar PV	Application
DE-02448	8/28/2017	2000	2200	Solar PV	Application
DE-02449	8/28/2017	2000	2200	Solar PV	Application
DE-02450	8/28/2017	2000	2200	Solar PV	Application
DE-02451	8/28/2017	2000	2200	Solar PV	Application
DE-02452	8/28/2017	2000	2200	Solar PV	Application
DE-02453	8/28/2017	2000	2200	Solar PV	Application
DE-02454	8/28/2017	2000	2200	Solar PV	Application
DE-02455	8/28/2017	2000	2200	Solar PV	Application
DE-02456	8/28/2017	2000	2200	Solar PV	Application
DE-02457	8/28/2017	2000	2200	Solar PV	Application
DE-02458	8/28/2017	2000	2200	Solar PV	Application
DE-02459	8/28/2017	2000	2200	Solar PV	Application
DE-02460	8/28/2017	2000	2200	Solar PV	Engineering Study
DE-02461	8/28/2017	2000	2200	Solar PV	Application
DE-02462	8/28/2017	2000	2200	Solar PV	Application
DE-02463	8/28/2017	2000	2200	Solar PV	Application
DE-02464	8/28/2017	2000	2200	Solar PV	Application
DE-02465	8/28/2017	2000	2200	Solar PV	Application
DE-02466	8/28/2017	2000	2200	Solar PV	Application
DE-02467	8/28/2017	2000	2200	Solar PV	Application
DE-02468	8/28/2017	2000	2200	Solar PV	Application
DE-02469	8/28/2017	2000	2200	Solar PV	Application
DE-02470	8/28/2017	2000	2200	Solar PV	Application
DE-02471	8/28/2017	2000	2200	Solar PV	Application
DE-02472	8/28/2017	2000	2200	Solar PV	Application
DE-02473	8/28/2017	2000	2200	Solar PV	Application
DE-02474	8/28/2017	2000	2200	Solar PV	Application
DE-02475	8/28/2017	2000	2200	Solar PV	Engineering Study

MPSC Case No.: U-18437
Respondent: R. J. Mueller
Requestor: ELPC
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Project Number	Date Application Received	Applied For (KW)	KVA	Generation Type	Status
DE-02501	9/6/2017	2000	2200	Solar PV	Application
DE-02502	9/6/2017	2000	2200	Solar PV	Application
DE-02503	9/6/2017	2000	2200	Solar PV	Application
DE-02504	9/6/2017	2000	2200	Solar PV	Application
DE-02505	9/6/2017	2000	2200	Solar PV	Application
DE-02506	9/6/2017	2000	2200	Solar PV	Engineering Study
DE-02507	9/6/2017	2000	2200	Solar PV	Engineering Study
DE-02508	9/6/2017	2000	2200	Solar PV	Application
DE-02509	9/6/2017	2000	2200	Solar PV	Application
DE17183	9/8/2017	2000	2200	Solar PV	Application
DE17184	9/8/2017	2000	2200	Solar PV	Application
DE17185	9/8/2017	2000	2200	Solar PV	Application
DE-02529	9/14/2017	2000	2200	Solar PV	Application
DE-02530	9/14/2017	2000	2200	Solar PV	Application
DE-02531	9/14/2017	2000	2200	Solar PV	Application
DE-02532	9/14/2017	2000	2200	Solar PV	Application
DE-02533	9/14/2017	2000	2200	Solar PV	Engineering Study
DE-02534	9/14/2017	2000	2200	Solar PV	Application
DE-02567	9/30/2017	2000	2200	Solar PV	Application
DE-02569	10/2/2017	360	360	Dynometer	Application
DE-02570	10/3/2017	20000	22400	Solar PV	Application
DE-02571	10/3/2017	20000	22400	Solar PV	Application
DE-02572	10/3/2017	20000	22400	Solar PV	Application
DE-02782	10/6/2017	20000	14300	Solar PV	Engineering Study
DE-02582	10/10/2017	4600	4600	Steam Turbine	Application
DE-02587	10/11/2017	2000	2200	Solar PV	Application
DE-02588	10/11/2017	2000	2200	Solar PV	Application
DE-02590	10/11/2017	2000	2200	Solar PV	Application
DE-02591	10/11/2017	2000	2200	Solar PV	Application
DE17186	10/12/2017	50000	49998	Solar PV	Engineering Study

MPSC Case No.: U-18437
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Requestor: ELPC
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Project Number	Date Application Received	Applied For (KW)	KVA	Generation Type	Status
DE17191	11/3/2017	3464	3464	Steam Turbine	Application
DE-02684	11/12/2017	2000	2200	Solar PV	Application
DE-02685	11/12/2017	20000	22500	Solar PV	Application
DE-02686	11/12/2017	20000	22500	Solar PV	Application
DE-02687	11/12/2017	20000	22500	Solar PV	Application
DE-02688	11/12/2017	20000	22500	Solar PV	Application
DE-02689	11/12/2017	20000	22500	Solar PV	Application
DE-02690	11/12/2017	20000	22500	Solar PV	Application
DE-02703	11/17/2017	20000	22000	Solar PV	Application
DE-02704	11/17/2017	20000	22000	Solar PV	Application
DE-02706	11/17/2017	20000	22000	Solar PV	Application
DE-02750	11/30/2017	2000	2200	Solar PV	Application
DE-02751	11/30/2017	2000	2200	Solar PV	Application
DE-02752	11/30/2017	2000	2200	Solar PV	Application
DE-02753	11/30/2017	2000	2200	Solar PV	Application
DE-02754	11/30/2017	2000	2200	Solar PV	Application
DE-02755	11/30/2017	2000	2200	Solar PV	Application
DE-02768	12/5/2017	3500	3500	Steam Turbine	Application
DE-02779	12/8/2017	2000	2000	Solar PV	Application
DE-02780	12/8/2017	2000	2000	Solar PV	Application
DE-02781	12/8/2017	2000	2000	Solar PV	Application
DE-02810	12/22/2017	20000	22500	Solar PV	Application
DE-02811	12/22/2017	20000	22500	Solar PV	Application
DE-02812	12/22/2017	20000	22500	Solar PV	Application
DE-02813	12/22/2017	2000	2200	Solar PV	Application

MPSC Case No.: U-18419
Respondent: K. J. Chreston/T. L. Schroeder
Requestor: MECNRDCSC
Question No.: MECNRDCSCDE-2.23
Page: 1 of 1

Question: Has DTE constrained the amount of solar and wind that can be built in a given year? If so, please specify what the limit is, and provide supporting materials for this assumption.

Answer: Yes, in Strategist, the amount of solar and wind that can be built in a given year was constrained to 1,000 MWs of wind and 500 MWs of solar. There is no supporting documentation for this assumption.

MPSC Case No.: U-18419
Respondent: T. L. Schroeder/K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-7.3 Supplemental
Page: 1 of 1

Question: Please refer to Workpaper KJC-41. Please provide the following information for the modeled system: location (latitude and longitude), azimuth, tilt, system nameplate in MW DC, system inverter rating in MW AC, and assumed total system losses."

Answer: KJC-41 represents a 20MW-AC solar project located in lower Michigan with a NCF-AC of 20%, which takes into account the azimuth, tilt, system inverter rating, and assumed total system losses.

Supplemental Response:

Model Input	**Assumption**
Latitude / Longitude	42.2º N / 83.3º W
Azimuth	0º (facing equator)
Tilt	Fixed tilt - 30º
System Nameplate MW_{dc}	25 MW
System Inverter Rating MW_{ac}	21 MW
Assumed Total System Losses	13.5%

MPSC Case No.: U-18419
Respondent: K. J. Chreston/T. L. Schroeder
Requestor: ELPC
Question No.: ELPCDE-6.6c
Page: 1 of 1

Question: Refer to Workpapers KJC-39 and KJC-479. In the KJC-39 file file, DTE assumes a 0.8% annual panel degradation for PV generation, found by dividing the GWh output in row 22 of a subsequent year by the previous year. In Workpaper KJC-479, DTE assumes a 0.5% annual panel degradation for PV generation.

c. Please indicate which value for annual panel degradation is used in each analytical step in this proceeding.

Answer: Existing renewable resources were modeled assuming a 0.8% annual panel degradation for PV generation. A 0.8% degradation factor was used for the high renewable sensitivity. Within the LCOE model, a 0.5% degradation factor was used. Within Strategist, an optimistic view was taken on new solar resources and no degradation factor was applied.

MPSC Case No.: U-18419
Respondent: T. L. Schroeder
Requestor: ELPC
Question No.: ELPCDE-5.42
Page: 1 of 1

Question: Did DTE assume the installation of any 1 axis tracking solar PV systems at any point in its IRP study period? If so, please provide all data on costs and operating characteristics. If not, please explain why it did not consider this technology.

Answer: No. Please reference my direct testimony, page TLS – 12, lines 21 - 24.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-7.2c
Page: 1 of 1

Question: Please refer to the various models utilized in the IRP.

c) Will this choice in part b) depend on whether or not there is a need for additional capacity?

Answer: The need to construct new generation in the model is based on the need to meet our minimum reserve margin requirements throughout the planning period. If there was no capacity need throughout the planning period, then no resources would be built unless units were added superfluously.

MPSC Case No.: U-18419
Respondent: D. D. Kirchner
Requestor: ELPC
Question No.: ELPCDE-1.18
Page: 1 of 1

Question: Please provide the GDS Associates demand response potential study referenced by Mr. Kirchner at page DDK-10.

Answer: See attachment U-18419 ELPCDE-1.18 GDS DR Potential Study Final Report.

GDS Associates, Inc.
ENGINEERS & CONSULTANTS

DTE ENERGY
Demand Response Potential Study

Prepared for:

DTE Energy

Final Report

April 20, 2016

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1 EXECUTIVE SUMMARY

This demand response (DR) potential study provides a roadmap for both policy makers and DTE Energy as they develop strategies and programs for reducing the peak summer electric demand in the DTE Energy service area. The report identifies a comprehensive set of DR program options and presents an analysis of the cost, benefits and potential summer peak demand savings associated with each DR program option. Demand Response is defined as changes in electric usage by retail customers from their normal consumption patterns in response to changes in the price of electricity over various time periods, or to incentive payments designed to induce lower electricity use at times of peak electric demand. GDS Associates, Inc. (GDS) used a systematic, bottom-up approach for developing estimates of DR for both the residential and non-residential (commercial and industrial) sectors. The study provides annual estimates of DR potential and associated benefits and costs for the period 2016-2035.

1.1 STUDY SCOPE

GDS Associates, the consulting firm retained by DTE Energy to conduct this DR potential study, produced the following estimates of DR potential:

- Technical potential
- Economic potential
- Achievable potential

Definitions of the types of energy efficiency potential are provided below.

Technical Potential | All technically feasible demand reductions are incorporated to provide a measure of the theoretical maximum DR potential. This assumes 100% of eligible customers will participate in all programs regardless of the cost-effectiveness.

Economic Potential | All DR programs included in technical potential are screened for cost-effectiveness by comparing the programs anticipated benefits and costs, specifically by using the current Michigan benefit/cost test (the “UCT” test). Only cost-effective DR programs are included in the economic potential. In accordance with guidance provided by DTE, all DR program capital costs, such as the cost of load control switches, are amortized over the assumed useful life of the equipment.

Achievable Potential | Achievable potential is the cost-effective DR potential that can practically be attained in a real-world program delivery scenario, assuming that a certain level of market penetration can be attained. Achievable potential takes into account barriers to convincing customers to participate in cost effective DR programs. Achievable savings potential savings is a subset of economic potential.

This potential study evaluated DR potential for two achievable potential scenarios:

1) **Base Case Scenario:** The Base Case scenario assumes that all cost-effective DR programs will be implemented by DTE Energy and that the legacy Residential Central Air Conditioning Load Control program will continue in its current state. No utility spending caps are placed on the achievable potential for this scenario.

2) **Smart Thermostat Scenario:** The Smart Thermostat scenario also assumes that all cost-effective DR programs will be implemented, but in this scenario:

    - The legacy Residential Central Air Conditioning Load Control program is fixed at its year end 2015 level of participation, and

- A new Smart Thermostat program is implemented in both the residential and non-residential (Commercial and Industrial or C&I) sectors.

As in the Base Case, no spending caps are placed on the achievable potential for this scenario.

1.2 Study Approach

The DR potential results were developed using customized versions of the GDS DR potential model (GDS DR Model) for the residential and non-residential sectors, and DTE Energy cost-effectiveness criteria including the most recent avoided electric avoided cost projections. Key model inputs such as typical per participant demand savings, demand response program participation rates and program delivery costs were obtained from various sources including:

1) Information provided by DTE Energy
2) Baseline studies conducted by DTE Energy
3) U.S. Department of Energy, Energy Information Administration (EIA)
4) Federal Energy Regulatory Commission (FERC) – National DR Model, DR Survey Data and Annual DR Reports
5) California Public Utilities Commission filings
6) Other recent DR potential studies

The GDS DR model is a spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following basic equation:

Achievable DR Potential	=	Per Customer CP Load for Eligible Customer Segment or End Use	X	Potentially Eligible Customers	X	Eligible Customer Participation Rate	X	Percent CP Load Reduction Per Participant

The DR model also allows the user the option of inputting an expected peak kW reduction value per participant instead of a percent savings factor.

1.3 Summary of Results

Table 1-1 and Table 1-2 show the achievable DR potential for each cost effective DR program, DTE's projected system peak, and the percentage of system peak load that the achievable potential represents. Figure 1-1 compares the achievable potential for the two achievable potential scenarios. Unless otherwise noted, all MW reductions shown in this report are at the customer meter.

Table 1-1: Achievable Potential for Base Case Scenario

Sector	DR Program	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Residential	Dynamic Peak Pricing Rate	88	172	251	325
	DLC of Central AC by Switch	195	195	195	195

	Residential Total	**283**	**367**	**446**	**520**
Non-Residential	Dynamic Peak Pricing Rate	46	93	139	185
	Special Rate for Electric Vehicle Charging	9	13	21	30
	Special Rate for Golf Cart Charging	3	7	10	14
	Special Rate for Thermal Electric Storage-Cooling	24	48	71	95
	Interruptible Rate	420	420	420	420
	C&I Total	**502**	**581**	**661**	**744**
All Sectors	**Total All Sectors**	**785**	**947**	**1,107**	**1,264**
	System Summer Peak (MW)	**12,591**	**12,733**	**12,693**	**12,574**
	Percent of System Peak	**6.2%**	**7.4%**	**8.7%**	**10.1%**

Table 1-2: Achievable Potential for Smart Thermostat Scenario

Sector	DR Program	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Residential	Dynamic Peak Pricing Rate	88	172	251	325
	DLC of Central AC by switch	195	195	195	195
	DLC of Central AC by Controllable Thermostat	14	62	99	96
	Residential Total	**296**	**429**	**545**	**616**
Non-Residential	Dynamic Peak Pricing Rate	46	93	139	185
	Special Rate for Electric Vehicle Charging	9	13	21	30

	Special Rate for Golf Cart Charging	3	7	10	14
	Special Rate for Thermal Electric Storage- Cooling	24	48	71	95
	DLC of Central AC by Controllable Thermostat	46	84	111	129
	Interruptible Rate	420	420	420	420
	Non-Residential Total	**549**	**664**	**772**	**873**
All Sectors	**Total All Sectors**	**845**	**1,093**	**1,317**	**1,489**
	System Summer Peak (MW)	**12,591**	**12,733**	**12,693**	**12,574**
	Percent of System Peak	**6.7%**	**8.6%**	**10.4%**	**11.8%**

Figure 1-1: Comparison of Achievable Potential Scenarios

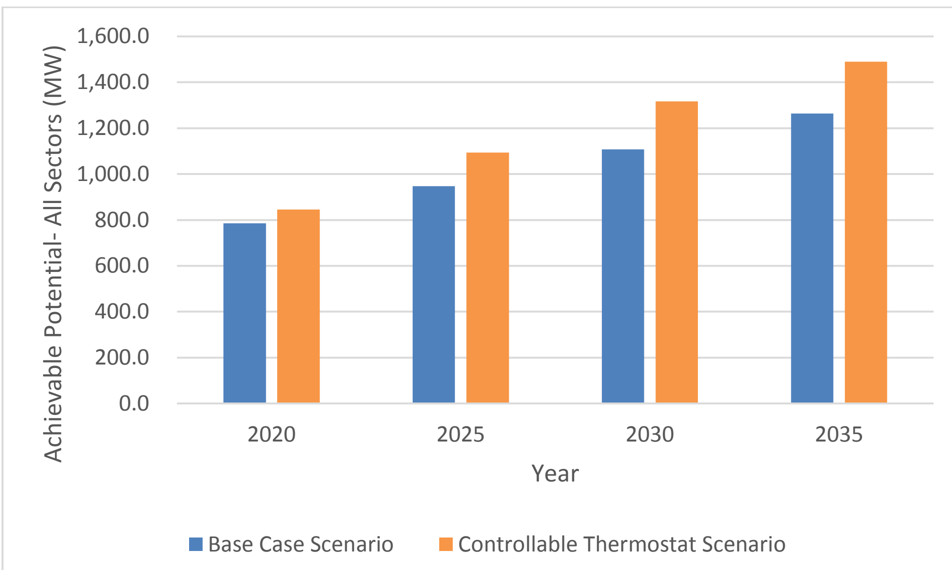


Table 1-3 shows the utility budgets that will be required to acquire the potential peak load reductions for each of the achievable potential scenarios.

Table 1-3: Average Annual Program Budgets for the Achievable Potential Scenarios (in millions)

	Base Case Scenario			Smart Thermostat Scenario		
Years	Residential	Non-Residential	Total	Residential	Non-Residential	Total
2016 - 2020	$7.43	$3.48	$10.91	$9.03	$8.40	$17.43
2021 - 2025	$8.55	$3.62	$12.17	$13.17	$7.62	$20.79
2026 -2030	$9.19	$4.15	$13.34	$17.32	$11.71	$29.03

2031 -2035	$9.48	$4.69	$14.17	$17.62	$10.47	$28.09

Table 1-4 shows the net present value of benefits and costs, and the cost-effectiveness of the Base Case and Smart Thermostat scenarios.

Table 1-4: Summary of Benefits, Costs on Cost-Effectiveness for Achievable Scenarios

Scenario	NPV Benefits	NPV Utility Costs	NPV Savings (Benefits - Costs)	UCT Ratio
Base Case	$654,085,428.80	$289,288,390.56	$364,797,038.24	2.26
Smart Thermostat	$949,873,879.38	$383,019,153.07	$566,854,726.31	2.48

1.4 Report Organization

The remainder of this report is organized as follows:

Section 2: Glossary of Terms defines key terminology used in the report.

Section 3: Introduction highlights the background, purpose and scope of this study.

Section 4: Demand Response Potential characterizes the DTE market for DR programs, presents the study approach and key assumptions and presents DR potential estimates and program costs.

2 Glossary of Terms

The following list defines many of the key demand response terms used throughout this DR potential study and in the GDS DR Potential Model.

Age of Existing Program: The number of years that the existing program being analyzed has been in operation.

Amortized Program Equipment Costs: The process of allocating the cost of an asset over the useful life of that asset.

Annual Number of Control Hours: The annual number of hours that a DR program or measure will reduce a participant's electrical demand.

Avoided Generation Cost per kW-Yr.: These are the generation capacity costs that are avoided due to the implementation of demand response.

Avoided Transmission & Distribution ($/kW-Yr.): These are the transmission and distribution costs that are avoided due to the implementation of demand response.

Base Participant CP Demand (kW): The total participant coincident (with the system peak) demand before any demand response reductions.

Base Sector CP Demand (kW): The total coincident (with the system peak) demand of all eligible customers before any demand response reductions.

Central Controller Hardware Cost: The cost of a central (utility) control system that is used to communicate with customer based control equipment such as switches. If the central controller is used by multiple programs, the costs should be split among these programs.

Central Controller Software Costs: The cost of central (utility) control system software that is used to communicate with customer based control equipment such as switches. If the central controller and its software are used by multiple programs, the software costs should be split among these programs.

Coincident Peak (CP) Load per Eligible Customer (kW): The participant coincident (with the system peak) demand per eligible customer before any demand response reductions.

Coincident Peak Demand Reduction (kW): The total coincident (with the system peak) demand reduction for all program participants.

Coincident Peak Demand Reduction @ Gen (kW): The total participant coincident (with the system peak) demand reduction, including line losses.

Control Equipment Useful Life (Years): The number of years that control equipment installed at the customer site is expected to operate before it needs to be replaced.

Cost to Serve Energy during Control ($/MWh): The cost to meet customer energy requirements during peak demand periods.

Cost to Serve Energy during Recovery ($/MWh): The cost to meet customer energy requirements during off peak demand periods.

Dynamic Peak Pricing: Dynamic pricing generally refers to the family of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis. The Dynamic Peak Pricing Rate currently offered by DTE Energy is a more static tiered TOU pricing rate that also includes a critical peak pricing component.

Direct Load Control: A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g., air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

Discount Rate: An interest rate applied to a stream of future costs and/or monetized benefits to convert those values to a common period, typically the current or near-term year, to reflect the time value of money. It is used in benefit-cost analysis to determine the economic merits of proceeding with the proposed project, and in cost-effectiveness analysis to compare the value of projects. The discount rate for any analysis is either a nominal discount rate or a real discount rate. A Nominal Discount Rate is used in analytic situations when the values are in then-current or nominal dollars (reflecting anticipated inflation rates).

Eligible Customers: The total number of customers that are eligible to participate in a demand response program.

Firm Load Reduction: Load reduction associated with a direct load control program with no customer override option.

Hierarchy Ranking: A ranking of DR programs (where 1 is the highest rank) that determines the order in which the same pool of eligible customers are allowed to participate in DR programs that are considered to interact with one another. The purpose of the hierarchy ranking is will avoid double counting of potential demand reductions.

Implementation, Admin, Marketing: Direct utility or energy efficiency organization costs to market, promote, operate, and manage the program.

Installation Cost per Unit – Equipment: The cost of equipment, such as a control switch, that is required at the customer site for participation in the program.

Installation Cost per Unit – Labor: The cost of labor associated with the installation of equipment, such as a control switch, that is required at the customer site for participation in the program.

Load Shifting Program: A demand response program that shifts a portion of customer load from on-peak to off peak hours.

Max Customer Participation Rate: The expected customer participation rate at the end of the study period.

Number of Control Units Per Participant: The number of control switches that are required for each program participant.

Participant Incentive ($/kW-Yr.): Incentives paid to program participants stated as $/kW-Yr.

Peak Demand Line Loss Factor: Percentage of electric energy lost because of the transmission of electricity.

Per Participant CP Reduction (kW): The per participant coincident (with the system peak) demand reduction that will result from participation in the DR program.

Program Participation Rate: Percent of total eligible market for the DR measure that will participate in the DR program in each year. For example, if the program is residential central AC load control, the program participation rate would be the number of program participants/the number of residential customers with central AC.

Program Savings Factor (Percent of CP Load): The percentage reduction in the participant coincident (with the system peak) demand due to participation in the DR program.

Rate of General Inflation: The periodic rate at which general consumer prices increase. The General Inflation Rate is normally determined as an historical trend, using the Consumer Price Index (CPI) as published by the U.S. Bureau of Labor Statistics.

Reserve Margin: The difference between the dependable capacity of a utility's system and the anticipated peak load for a specified period.

Saturation Percentage of Targeted End Use: The percentage of eligible customers that have the end use that will be controlled by the DR program.

Start of Slow Growth (Year #): The year on the market adoption curve that slow growth in customer participation will begin.

Units Replaced at End of Useful Life: The number of units (such as control switches) that will need to be replaced at the end of their useful life.

Utility Cost Test (UCT): The utility cost test, also known as the program administrator cost test, examines the costs and benefits of the energy efficiency or demand response program from the perspective of the entity implementing the program (utility, government agency, nonprofit, or other third party). The costs included in the UCT include overhead and incentive costs. Overhead costs are administration, marketing, research and development, evaluation, and measurement and verification. Incentive costs are payments made to the customers to offset purchase or installations costs. The benefits from the utility perspective are the savings derived from not delivering the energy to customers. Depending on the jurisdiction and type of utility, the “avoided costs” can include reduced wholesale electricity or natural gas purchases, generation costs, power plant construction, transmission and distribution facilities, ancillary service and system operating costs, and other components.

Variable Program Equipment Costs: Program equipment costs, such as the cost of control switches that vary with the number of program participants.

Weighted Average Cost of Capital (WACC): The weighted average cost of capital (WACC) is the rate that a company is expected to pay on average to all its security holders to finance its assets.

3 INTRODUCTION

3.1 BACKGROUND

This demand response (DR) potential study provides a roadmap for both policy makers and DTE Energy as they develop additional strategies and programs for reducing the peak summer electric demand in the DTE Energy service area. The report identifies a comprehensive set of DR program options and presents an analysis of the cost, benefits and potential summer peak demand reductions associated with each DR program option. Demand Response (DR) is defined as changes in electric usage by retail customers from their normal consumption patterns in response to changes in the price of electricity over various time periods, or to incentive payments designed to induce lower electricity use at times of peak electric demand. GDS used a systematic, bottom-up approach (at the customer segment and end use level) to develop estimates of DR potential for both the residential and non-residential (commercial and industrial) sectors. This study provides annual estimates of DR potential the period 2016-2035.

The key objectives of this study include:

- Conduct a 20-year bottom-up DR potential study to determine the technical, economic and achievable potential of specific DR program options to reduce summer peak demand for electricity in the DTE Energy service area.
- Identify the costs and benefits of all cost-effective programs.
- Identify the total and incremental annual DR program budget (in excess of the current DR program budget) that would be required to acquire all achievable cost-effective DR potential.

This potential study evaluated DR potential for two achievable potential scenarios:

1) **Base Case Scenario:** The Base Case scenario assumes that all cost-effective DR programs will be implemented by DTE and that the legacy Residential Central Air Conditioning Load Control program will continue in its current state. No utility spending caps are placed on the achievable potential for this scenario.

2) **Smart Thermostat Scenario:** The smart thermostat (Smart T) scenario also assumes that all cost-effective DR programs will be implemented, but in this scenario:

    - The legacy Residential Central Air Conditioning Load Control program is fixed at its year end 2015 level of participation, and
    - A new Smart Thermostat program is implemented in both the residential and non-residential sectors.

As in the Base Case, no spending caps are placed on the achievable potential for this scenario.

4 DEMAND RESPONSE POTENTIAL

Demand Response is defined as changes in electric usage by retail customers from their normal consumption patterns in response to changes in the price of electricity over various time periods, or to incentive payments designed to induce lower electricity use at times of peak electric demand. GDS used a systematic, bottom-up approach for developing estimates of DR for both the residential and non-residential (commercial and industrial) sectors. This study provides annual estimates of DR potential the period 2016 -2035.

This section of the report includes:

- Characterization of peak electric demand consumption in the DTE Energy service area
- Description of all DR options considered in this potential study
- Discussion of the analytical approach used to determine DR potential and DR cost-effectiveness
- Key study assumptions including program participation rates, per participant demand reductions and program costs
- DR potential results including potential summer peak load reductions and associated program costs, benefits and cost-effectiveness

4.1 CHARACTERIZATION OF PEAK DEMAND CONSUMPTION

Customer Segmentation

The first step in our DR potential study was to segment the market into customer segments that are relevant for analyzing DR potential, given available data. The first level of segmentation was by sector: Residential and Non-Residential (Commercial and Industrial or C&I) customers. Within residential customers, we further segmented the population by the saturation of end uses that are typically targeted in DR programs such as central air conditioning (CAC) and electric water heating. For C&I customers, segmentation is based on the maximum customer demand values and then the saturation of targeted end uses such as packaged and split air conditioning systems and electric water heating.

Table 4-1 presents total number of customers in each segment in 2015, the coincident summer demand for each customer segment and the average coincident demand per customer. Coincident demand is segment (or average customer) load at the time of the system summer peak. The breakdown of customers by rate class and size of coincident peak load was provided by DTE.

Table 4-1: Number of Customers by Class and Coincident Peak Summer Demand

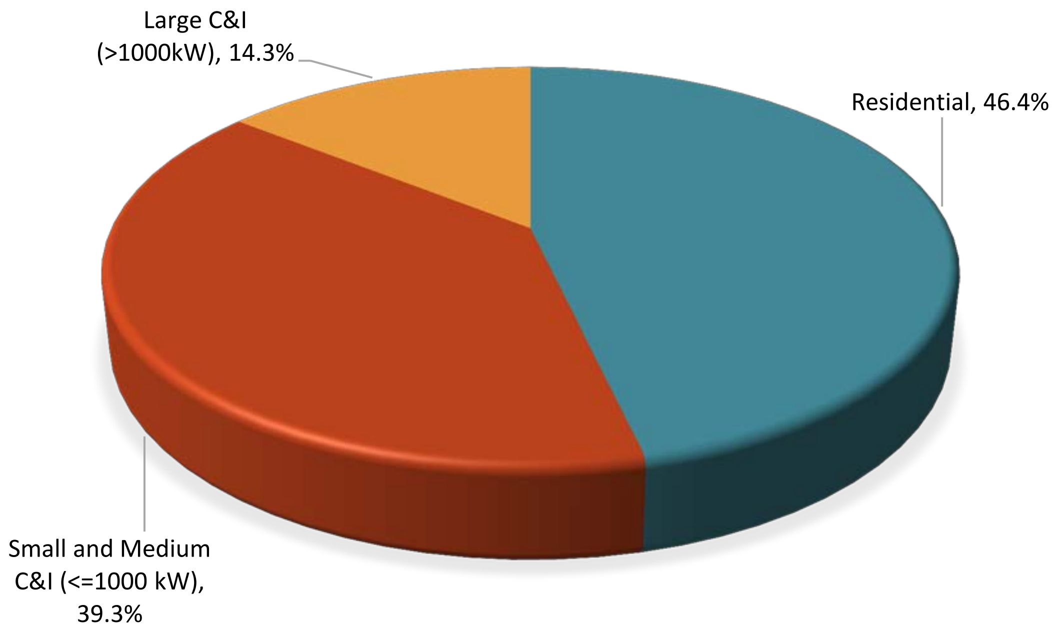
Customer Segment	Number of Customers	Segment Peak (Summer MW)[1]	Per Customer Peak (kW)
Residential	1,948,916	5,279	2.7
Small and Medium C&I (<=1000 kW)	197,440	4,475	22.7
Large C&I (>1000kW)	731	1,625	2222.8
Total	2,147,087	11,379	

[1] Coincident with the system peak.

The end use saturations used to further characterize the market for potential DR programs were taken from the 2013 DTE Residential Appliance Saturation Survey and Commercial Baseline Study.

Figure 4-1 shows the contribution that each identified customer segment made to the DTE system peak in 2015. Commercial and industrial customers combined have the greatest contribution to the system summer peak at 53.6%. However, of the segments identified in this study, residential customers have the largest contribution with 46.4%.

Figure 4-1: Contribution to DTE Summer Peak Demand by Customer Segment



Peak Demand Forecast

The summer peak demand reference forecast was calculated by GDS, with load factors provided by DTE[2]. It is presented below for selected years in Table 4-2. This is the baseline forecast of DTE's summer peak demand without any new energy efficiency or demand response programs.

Table 4-2: DTE Peak Demand Forecast

	2016	2020	2025	2030	2035
System Summer Peak (MW)	12,280	12,591	12,733	12,693	12,574

Customer Forecast

DTE provided GDS with a reference forecast of the number of customers in each segment for the period 2016 through 2035. This forecast was used to estimate participation rates in each segment, by program. The customer forecasts for selected forecast years are presented below in Table 4-3.

Table 4-3: DTE Customer Forecast by Segment

[2] Load factors provided by Derek Kircher, Principal Supervisor- Demand Side Management of DTE in a 2/16/2016 phone call. A load factor of 65% was used for industrial and residential load factors are between 35-40%.

	2016	2020	2025	2030	2035
Residential	1,943,880	1,942,990	1,941,697	1,938,789	1,937,876
Small and Medium C&I (<=1000 kW)	198,296	198,355	199,363	198,357	198,313
Large C&I (>1000 kW)	761	806	796	802	799

4.2 Demand Response Options

This study included analysis of a comprehensive set of DR programs (programs) that fall into two main categories, Direct Load Control and Rate Programs. Table 4-4 provides a brief description of these DR programs and identifies the eligible customer segment for each program.

After discussion with DTE, GDS decided on two achievable potential scenarios. The "base case" scenario includes rate programs and all direct load control programs that use load control switches. The DLC AC program is not expanded in this scenario, as DTE does not wish to expand it with load switches. The "smart thermostat scenario" includes everything that the base case scenario does, and also new load control of central AC customers in the residential and non-residential sectors using a smart controllable thermostat. For this scenario, central AC in the residential sector (both by switch and thermostat) is considered one program. Because there are less than 1000 non-residential AC direct load control customers in the existing program, these customers are included in the residential AC direct load control program.

Table 4-4: DR Programs and Eligible Markets

DR Programs	Brief Description	Eligible Customer Segments
Direct Load Control		
Direct Load Control of Central Air Conditioning	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle)	Residential Small & Medium C&I
Direct Load Control of Window Air Conditioners	The air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle)	Residential
Direct Load Control of Water Heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours. Can also be used for energy storage.	Residential Small & Medium C&I
Direct Load Control of Swimming Pool Pumps,	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hrs.	Residential
Direct Load Control of Lighting	The lighting load is remotely or dimmed partially shut off by the system operator for periods normally ranging from 2 to 4 hours	Small & Medium C&I
Smart Controllable	The system operator can remotely raise	Residential

DR Programs	Brief Description	Eligible Customer Segments
Thermostats	the AC's thermostat set point during peak load conditions, lowering AC and/or heating load.	Small & Medium C&I
Rate Programs		
Interruptible Rate	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period. The interruption is mandatory. No buy-through options are available.	Large C&I
Dynamic Peak Pricing Rate	Dynamic pricing generally refers to the family of rates that offer customers time-varying electricity prices on a day-ahead or real-time basis. The Dynamic Peak Pricing Rate currently offered by DTE Energy is a more static tiered TOU pricing rate that also includes a critical peak pricing component.	Residential Small & Medium C&I (Secondary only)
Special Rate for Golf Cart Charging	Special rate service for golf courses that charge electric golf carts off-peak	Golf Courses
Special Rate for Plug In Electric Vehicles	Special rate service for electric vehicles that charge off-peak	Residential Small & Medium C&I
Special Rate for Electric Thermal Storage- Cooling	Special rate service for the use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods	Small & Medium C&I

4.3 Demand Response Potential Assessment Approach

The analysis for this study was conducted using GDS Demand Response Model (DR Model). The GDS DR model is a spreadsheet tool that allows the user to determine the achievable potential for a demand response program based on the following two basic equations that can be chosen be the model user.

If the model user chooses to base the estimated potential demand reduction on a percent of the total per participant coincident peak (CP) load, then:

$$\text{Achievable DR Potential} = \text{Per Customer CP Load for Eligible Customer Segment} \times \text{Potentially Eligible Customers} \times \text{Eligible Customer Participation Rate} \times \text{Percent CP Load Reduction Per Participant}$$

If the model user chooses to base the estimated potential demand reduction on a per customer CP load reduction value, then:

Achievable DR Potential	=	Potentially Eligible Customers	X	Eligible Customer Participation Rate	X	CP Load Reduction Per Participant

Achievable Potential is the cost-effective DR potential that can practically be attained in a real-world program delivery scenario, assuming that a certain level of market penetration can be attained. Achievable potential takes into account real-world barriers to convincing customers to participate in cost effective DR programs. Achievable savings potential savings is a subset of economic potential.

The cost-effectiveness of each measure is also determined within the model for the UCT. Benefits are based on avoided demand, energy (including load shifting) and T&D costs. Costs include incremental costs (such as control switches), fixed costs (such as central controller), program administrative and marketing costs and program incentives. Incremental equipment costs are included for both new and replacement units to account for units that are replaced at the end of their useful life. The user also has the option to amortize incremental program equipment costs.

In addition to the achievable DR potential the GDS DR Model includes estimates of technical and economic potential. These are defined as follows:

Technical Potential | All technically feasible demand reductions are incorporated to provide a measure of the theoretical maximum DR potential. This assumes 100% of eligible customers will participate in all programs regardless of cost-effectiveness.

Economic Potential | Only cost-effective DR programs are included in the economic potential. In accordance with guidance provided by DTE all DR program utility capital costs, such as the cost of load control switches, associated with DR program delivery are amortized over the assumed useful life of the equipment.

Cost-Effectiveness Framework | The framework for assessing the cost-effectiveness of DR programs is based *on A Framework for Evaluating the Cost-Effectiveness of Demand Response, Prepared for the National Forum on the National Action Plan on Demand Response,* Prepared for the National Forum on the National Action Plan on Demand Response.[3]

For the purposes of this study, the UCT was used to assess the benefits and costs associated with the DR programs, as prescribed by the State of Michigan. The UCT test measures benefits and costs from the perspective of the utility. The benefits accounted for in the UCT are those attributable to avoided capacity, energy (including energy shifted to off-peak hours) and transmission and distribution (T&D). The UCT costs include any customer incentives, utility equipment (costs) associated with the purchase and installation of enabling technologies amortization of equipment costs and program implementation, administrative and marketing costs.

The cost-effectiveness analysis was conducted for each DR program included in the study. The GDS DR model was the used to conduct the cost-effectiveness assessment.

[3] Study was prepared by Synapse Energy Economice and the Regulatory Assistance Project, February 2013.

4.4 AVOIDED COSTS AND OTHER ECONOMIC ASSUMPTIONS

The avoided costs used to determine utility benefits were provided by DTE Energy. They can be found in Appendix E. Avoided electric generation capacity refers to the benefit resulting from DR programs achieved by a reduction in the need for new peaking generation capacity. Demand response can also produce energy related benefits. If the demand response is considered "load shifting", such as electric water heating, the consumption of energy is shifted from the control period to the period immediately following the period of control. GDS assumes that the energy is shifted with no loss of energy. For power suppliers, this shift in the timing of energy can produce benefits from either the production of energy from lower cost resources or the purchase of energy at a lower rate. If the program is not considered to be "load shifting", such as lighting, the measure is turned off during peak control hours, and the energy is saved altogether. While DR programs can also potentially delay the construction of new substation facilities, which is reflected in avoided T&D costs, no specific avoided T&D costs were provided by DTE Energy.

The discount rate used in this study was 9.31%. A peak demand line loss factor of 6.8%, and reserve margin is 14.8% (for firm load reduction such as direct load control) were also applied to demand reductions at the customer meter. All of these values were provided by DTE Energy.

The number of annual control hours for all DLC programs was assumed to be 80. TOU control hours are between 11am and 7pm Monday to Friday[4], or 2080 annual hours. Controllable thermostats are also on a TOU rate, so control hours would also be 2080 annual hours. Dynamic Peak Pricing on-peak control hours are between 3pm and 7pm Monday to Friday[5], or 1040 annual hours.

The number of control units per participant was assumed to be 1 for all direct load control programs using switches. However, for controllable thermostats, some participants have more than one thermostat. The average number of thermostats per home was assumed to be 1.12[6].

Useful Lives of Load Control Devices and AMI Meters

GDS assumes a useful life of load control switches to be 10 years[7]. This life was used for all direct load control measures in this study. AMI meters used for rate programs in this study are also assumed to have a useful life of 10 years.

4.5 CUSTOMER PARTICIPATION RATES

The assumed customer participations rates for each DR program are a key driver of achievable DR potential estimates. Customer participation rates reflect the total number of eligible customers that are likely to participate in a DR program. An eligible customer is defined as a customer that has the option to participate in a DR program. For DLC programs, eligibility is determined by whether or not a customer has the end use equipment that will be controlled. For rate programs eligibility can be limited by the size and type of customer.

Existing Demand Response Programs

DTE Energy currently has a residential and small commercial DLC central air conditioning program. At

[4] DTE Rate Schedule, Final Order Case No. U-17767, DTE Energy Company.
[5] DTE Rate Schedule, Final Order Case No. U-17767, DTE Energy Company.
[6] According to DTE's residential saturation survey, 12% of homes have more than one thermostat. Assuming that these homes have two thermostats, the average number of thermostats per home would be 1.12.
[7] Pennsylvania, Act 129 2013 Order

the end of 2015, there were 277,186 residential participants and 906 small commercial participants. The company also has a residential and small commercial dynamic peak pricing rate program and an interruptible rate program. At the end of 2015, there were 1500 participants, with a max of 5000 eligible customers. The interruptible rate program has not been called on recently and it is assumed that it will continue at its current level of participation with not new interruptible load over the 20 year study horizon. DTE Energy also recently implemented a TOU program, but there are no participants yet. Participation in current DR programs was considered in the development of participation rate assumptions and the analysis of DR potential.

Eligible Market Size

Table 4-5 and Table 4-6 provide information on the size of the eligible markets for residential and non-residential DR programs, respectively. For the residential TOU program, all residential customers were assumed to be eligible. Double-counting savings from DR programs that affect the same end uses is a common issue that must be addressed when calculating the DR savings potential. For example, a customer cannot elect to participate in both DLC programs and rate programs, and claim savings from both programs for curtailing the same end use. GDS has determined a hierarchy for our analytical approach to ensure that this does not occur. This hierarchy establishes the type of DR program that will be counted if a participant has the option to participate in more than one DR program that affects the same end use. For some C&I rate based DR programs, eligible customers were limited. For example a special TOU rate for golf cart charging is limited to the number of golf course customers in the DTE Energy service area. Other examples of limited customer eligibility for rate based DR programs include Interruptible Rates and a special TOU rate for plug-in electric vehicles.

For direct load control, the size of the eligible market in 2016 was determined by multiplying DTE's forecast of 2016 customers by the saturation of the end use obtained from DTE's 2015 Appliance Saturation Study for residential and DTE's 2013 Commercial Baseline Study for non-residential. This was done for each year through 2035. In general, the hierarchy of DR programs is accounted for by subtracting the number participants in a higher priority program such as dynamic peak pricing (DPP) from the eligible market for a lower priority program such as direct load control of central air conditioning. Refer to Table 4-7 for the hierarchy levels for each demand response program.

Table 4-5: Eligible Residential Customers for Achievable Potential in Each DR Program

Program	Saturation	Eligible Residential Customers 2020	Eligible Residential Customers 2025	Eligible Residential Customers 2030	Eligible Residential Customers 2035
Dynamic Peak Pricing	100% minus TOU participants	1,916,926	1,876,462	1,827,066	1,771,850
DLC Existing Central AC by Switch	Only existing customers	278,092	278,092	278,092	278,092
DLC Central AC by Controllable Thermostat	65% minus TOU and CPP participants	1,072,753	962,801	855,724	754,656
DLC Room AC	28% minus TOU and CPP participants	413,882	286,541	165,336	52,113

DLC Electric Water Heaters	14% minus TOU and CPP participants	135,057	2,536	0	0
DLC Pool Pumps	8% minus TOU and CPP participants	15,560	0	0	0

Table 4-6: Eligible C&I Customers for Achievable Potential in Each DR Program

Program	Saturation	Eligible C&I Customers 2020	Eligible C&I Customers 2025	Eligible C&I Customers 2030	Eligible C&I Customers 2035
Dynamic Peak Pricing Rate	100%	194,638	195,627	194,639	194,596
Special Rate for Plug In Electric Vehicles	100% of EVs	5,979	8,891	14,169	20,867
Special Rate for Golf Cart Charging	100% of golf courses	480	480	480	480
Special Rate for thermal electric storage- cooling rate	78%	153,414	154,193	153,414	153,381
Direct load control of central air conditioning by controllable thermostat	76.5% minus DPP and TES participants	136,905	123,582	109,027	95,064
Direct load control of electric water heaters	78% minus DPP and TES participants	136,047	119,282	101,313	83,928
Direct load control of commercial lighting	67% minus DPP participants	116,989	102,912	87,794	73,180
Interruptible rate	Only existing customers	62	62	62	62

Table 4-7: Hierarchy for Demand Response Programs

Customer Segment	DR Option
Residential	Dynamic Peak Pricing
	Direct Load Control
Non-Residential	Dynamic Peak Pricing (DPP)
	Special Rate for Plug In Electric Vehicles
	Special Rate for Golf Cart Charging

	Special Rate for Thermal Electric Storage- Cooling
	Direct Load Control

In some cases, a program that is higher in the hierarchy, may have no impact on a lower ranked program. For example, a customer that participates in an off peak electric vehicle charging program can also participate in an air conditioning direct load control program. These types of judgements were made for each DR program that was analyzed to eliminate any double counting of DR potential.

Residential Participation Rates

All residential participation rates used in this potential study can be seen in Table 4-8. Program participation and impacts (demand reductions) for residential customers were assumed to begin in 2016. For residential direct load control programs, a maximum 40% penetration rate in the last year of the study period (2035) was assumed to determine potential peak load reduction savings. In other words, a participation rate of 40% of residential customers with central air conditioners was assumed by the year 2035. The participation rate of 40% is assumed to be the maximum penetration rate and no further installations of new load control devices occur after that time. A 20% penetration rate at year 10 (2025) was assumed for all new direct load control programs. DTE's residential central air conditioning program is currently at a 19% participation rate, so the remaining 21% for this DLC program was allocated to new customers by thermostat. The 40% participation rate was derived from the actual participation rates for DLC programs of 20 utilities around the country. That participation rate data can be found in Appendix B.

The participation rate for the DPP program is based on a review of a number of data sources, including the 2009 FERC Demand Response Model[8], 2012 FERC Survey on Demand Response[9], and other potential studies.

Table 4-8: Participation Rates for Residential DR Programs

DR Program	Residential Participation Rate
Dynamic Peak Pricing Rate	30% after 20 years
Direct load control of central air conditioning by controllable thermostat	21% after 20 years
Direct load control of existing central air conditioners by switch	19% for every year
Direct load control of central air conditioners by switch	40% after 20 years
Direct load control of room air conditioners	40% after 20 years
Direct load control of electric water heaters	40% after 20 years
Direct load control of swimming pool pumps, water garden pumps, hot tubs pumps and heating elements	40% after 20 years

Non-Residential Participation Rates

[8] Can be found at: https://www.ferc.gov/industries/electric/indus-act/demand-response/dr-potential/assessment.asp
[9] Can be found at: https://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp

Participation rates for C&I DR programs can be seen in Table 4-9. Participation rate assumptions for the C&I sector are based on a review of actual DR program participation rates from the following sources:

- **FERC 2012 Survey on Demand Response and Advanced Metering** - This national electric industry survey provides a unique database to support decisions by utilities and government policy makers.
- **Energy Information Administration (EIA) Form 861 Data** - The Form EIA-861 data files includes participation data for dynamic pricing and direct load control.

GDS also reviewed number of recent DR potential studies for other utilities and states to inform its judgement on the most appropriate assumptions for DR participation rates.

Table 4-9: Non-Residential DR Program Participation Rates

DR Program	C&I Participation Rate
Dynamic Peak Pricing Rate	30% after 20 years
Special Rate for Plug in Electric Vehicles	90% after 20 years
Special Rate for Golf Cart Charging	50% after 20 years
Special Rate for Thermal Electric Storage- Cooling Rate	6% after 20 years
Direct load control of central air conditioning by controllable thermostat	30% after 20 years
Direct load control of central air conditioners by switch	30% after 20 years
Direct load control of electric water heaters	30% of customers with standalone electric water heaters after 20 years
DLC Commercial Lighting	30% after 20 years

4.6 LOAD REDUCTION ASSUMPTIONS

Table 4-10 presents the per participant load reductions impact assumptions for each DR program. Impact assumptions are based on actual reported savings data for DTE DR programs or pilot programs, where they exist. Where there are no existing programs, load reduction impacts are based on the FERC 2012 Survey on Demand Response and Advanced Metering or engineering calculations. Specific sources use for each DR option can be found in Appendix C.

Table 4-10: Load Reduction Assumptions

DR Program	Unit of Impact	Load Reduction
Residential		
Time of Use Rate	Per Customer % Impact	30.29%

Dynamic Peak Pricing Rate	kW load reduction per customer (summer)	0.61 kW
Direct load control of central air conditioners	kW load reduction per customer (summer)	0.7 kW
Direct load control of swimming pool pumps, water garden pumps, hot tubs pumps and heating elements	kW load reduction per customer (summer)	1.36 kW
Direct load control of controllable thermostats	kW load reduction per customer (summer)	0.61 kW
Direct load control of room air conditioners	kW load reduction per customer (summer)	0.45 kW
Direct load control of water heaters	kW load reduction per customer (summer)	0.25 kW
Non-Residential		
Dynamic Peak Pricing Rate	Per Customer % Impact	14%
Special Rate for electric vehicles	kW load reduction per customer (summer)	1.62 kW
Special Rate for golf carts charging	kW load reduction per customer (summer)	56.25 kW
Special Rate for Thermal Electric Storage- Cooling rate	kW load reduction per customer (summer)	10.3 kW
Direct load control of central air conditioning by controllable thermostat	kW load reduction per customer (summer)	4.5 kW
Direct load control of electric water heaters	kW load reduction per customer (summer)	0.9 kW
Direct load control of commercial lighting	Per Customer % Impact	9%
Interruptible rate	Per Customer % Impact	100%

4.7 Program Costs

Table 4-11 shows the program costs that were assumed for each demand response program. It was generally assumed that there would be one program manager for all rate programs combined by sector (residential/non-residential), and one support staff for each program: for example, there is one program manager to manage the residential DPP program, and one support staff for that program. The residential direct load control of existing AC by switch and thermostat are one total program, so all of the administration costs were included in the existing AC switch component of the program. There are one-time program development costs for new programs that are included in the first year of the analysis. Since the implementation of room AC and water heater switches is very similar, the cost was split between the two programs. Each program includes a $50,000/year evaluation cost. It was assumed to cost $50 per new participant for marketing. This does not include existing customers or customers that were participating in the program the previous year. All program costs were escalated each year by the general rate of inflation assumed for this study.[10]

[10] The general rate of inflation used for this study was 2.0%. This was provided by DTE Energy.

Table 4-11: Program Cost Assumptions

Sector	DR Program	Administration Cost	Implementation Cost	Evaluation Cost	Marketing	Total Amortized Cost of Newly Installed Hardware	Central Controller Hardware and Software Cost	Notes
Residential	**Dynamic Peak Pricing Rate**	$118,500 per year (plus inflation)	$0 (existing program)	$50,000	$50 per new participant	$0 (AMI meters are already installed)	$0 (AMI meters are already installed)	0.5 program manager and 0.5 support staff
	Direct load control of existing central air conditioners by switch	$173,800 per year (plus inflation)	$0 (existing program)	$50,000	$50 per new participant	$41,314,238	$91,303	Includes admin and evaluation cost for Existing CAC and Thermostat (1 program total)
	Direct load control of central air conditioning by controllable thermostat	$0, included in existing CAC	$200,000 (one year only)	$25,000, partially included in existing CAC	$50 per new participant	$31,740,598	$91,303	Do not need full implementation cost b/c CAC already exists
	Direct load control of room air conditioners	$118,500 per year (plus inflation)	$200,000 (one year only)	$50,000	$50 per new participant	$8,426,326	$91,303	Implementation and admin cost split between RAC & EWH
	Direct load control of electric water heaters	$118,500 per year (plus inflation)	$200,000 (one year only)	$50,000	$50 per new participant	$585,762	$91,303	Implementation and admin cost split between RAC & EWH

	Direct load control of swimming pool pumps	$118,500 per year (plus inflation)	$400,000 (one year only)	$50,000	$50 per new participant	$119,340	$91,303	Different implementation from RAC and EWH, full cost
	Dynamic Peak Pricing Rate	$173,800 per year (plus inflation)	$0 (existing program)	$50,000	$50 per new participant	$0 (AMI meters are already installed)	$0 (AMI meters are already installed)	1 program manager and 1 support staff
Non-Residential	**Special Rate for Electric Vehicles**	$86,900 per year (plus inflation)	$0 (existing program)	$50,000	$50 per new participant	$3,217,988	$0	1 Program Manager and 1 support staff for both the GofCart and PEV Programs
	Special Rate for Golf Cart Charging	$86,900 per year (plus inflation)	$200,000 (one year only)	$50,000	$50 per new participant	$0	$0	1 Program Manager and 1 support staff for both the GofCart and PEV Programs
	Special Rate for Thermal Electric Storage- Cooling	$142,200 per year (plus inflation)	$200,000 (one year only)	$50,000	$50 per new participant	$0	$0	1 program manager, 0.5 support staff
	Direct load control of central air conditioning by controllable thermostat	$142,200 per year (plus inflation)	$200,000 (one year only)	$50,000	$50 per new participant	$49,682,021	$91,303	1 program manager, 0.5 support staff
	Direct load control of electric water heaters	$86,900 per year (plus inflation)	$200,000 (one year only)	$25,000	$9 per new participant	$2,029,404	$56,038	0.5 program manager and 0.5 support staff
	Direct load control of commercial lighting	$118,500 per year (plus inflation)	$400,000 (one year only)	$50,000	$50 per new participant	$40,087,538	$56,038	0.5 program manager and 1 support staff
	Interruptible rate	$86,900 per year (plus inflation)	$0 (existing program)	$0	0	$0	$0	0.5 program manager and 0.5 support staff

For our analysis, expenditures on direct load control computer equipment and load control switches were amortized over the life of switch. The total cost to DTE per customer for the equipment was assumed to be $200[11] for the installation of the switch and a second meter. The customer must have an electrician wire in a second meter stand and an AC/10 box for DTE to make the connection to. The estimated cost to the customer of this installation is $300. This cost was not included in this potential study because it is not a cost to DTE and therefore not part of the UCT. The cost of a controllable thermostat including installation labor is $268.72[12]. GDS assumed that DTE would own the thermostat. Rate programs were assumed to have no equipment cost.

Incentives paid to consumers annually were assumed to be $27.36 per kW for residential direct load control programs. This incentive amount is based on an average savings of $20.55 per household for DTE's current DLC AC program. The incentive was adjusted to account for a load reduction of 0.7 kW per household, along with the line loss factor of 6.8%. $27.36 was used for all DLC programs and $0 was used for all rate programs. For non-residential direct load control programs an incentive of $40 -$42 per kW was assumed with the slightly higher incentive being paid for direct load control of air conditioning. These incentives are based on a review of incentives for similar load control programs in other states. An initial central controller hardware of $25,000 is needed at the start of each program and is assumed to be replaced after 10 years, with an additional $5,000 per year for software updates. This is only for direct load control programs (including control of thermostats), not rate programs.

4.8 COST-EFFECTIVENESS RESULTS

Cost-effectiveness was determined based on screening with the UCT. Table 4-12 and Table 4-13 show the residential and non-residential net present values of the total benefits, costs, and savings, along with the UCT ratio for each program.

Table 4-12: Residential NPV Benefits, Costs, Savings, and UCT Ratios for Each Demand Response Program

Scenario	Demand Response Measure	NPV Benefits	NPV Utility Costs	NPV Savings (Benefits - Costs)	UCT Ratio
Base Case	Dynamic Peak Pricing	$108,882,868.52	$17,089,240.77	$91,793,627.76	6.37
	DLC Central AC-Only Existing	$172,998,425.81	$72,671,175.18	$100,327,250.63	1.92
	DLC Room AC	$13,149,242.28	$18,335,963.58	-$5,186,721.30	0.72
	DLC Electric Water Heaters	$592,240.02	$3,334,561.53	-$2,742,321.51	0.18
	DLC Pool Pumps	$429,946.97	$2,739,430.20	-$2,309,483.23	0.16
	Program Totals	**$296,052,723.60**	**$114,170,371.25**	**$181,882,352.35**	**2.59**
Smart Thermostat Scenario	Dynamic Peak Pricing	$108,882,868.52	$17,089,240.77	$91,793,627.76	6.37
	DLC Central AC - Only Existing	$172,998,425.81	$72,671,175.18	$100,327,250.63	2.38

11 Cost provided by DTE
12 MEMD Tier 3 Thermostat

	Controllable Thermostats	$95,709,906.47	$38,063,399.07	$57,646,507.40	2.51
	DLC Room AC	$13,149,242.28	$18,335,963.58	-$5,186,721.30	0.72
	DLC Electric Water Heaters	$592,240.02	$3,334,561.53	-$2,742,321.51	0.18
	DLC Pool Pumps	$429,946.97	$2,739,430.20	-$2,309,483.23	0.16
	Program Totals	**$391,762,630.07**	**$152,233,770.32**	**$239,528,859.75**	**2.57**

Table 4-13: Non-Residential NPV Benefits, Costs, Savings, and UCT Ratios for Each Demand Response Program

Scenario	Demand Response Measure	NPV Benefits	NPV Utility Costs	NPV Savings (Benefits - Costs)	UCT Ratio
Base Case	Dynamic Peak Pricing	$59,463,767.31	$4,145,453.95	$55,318,313.36	14.34
	Electric Vehicle Charging Stations Off Peak	$9,822,856.29	$5,739,429.09	$4,083,427.20	1.71
	Charging of Golf Carts Off Peak	$4,327,139.36	$2,421,628.26	$1,905,511.10	1.79
	Thermal Electric Storage- Cooling Rate	$30,497,615.44	$24,492,293.61	$6,005,321.83	1.25
	DLC Electric Water Heaters	$4,176,201.15	$5,471,605.11	-$1,295,403.96	0.76
	DLC Commercial Lighting	$22,637,453.46	$52,793,513.06	-$30,156,059.60	0.43
	Interruptible Rate	$327,556,523.38	$166,874,623.65	$160,681,899.73	1.96
	Program Totals	**$458,481,556.39**	**$261,938,546.74**	**$196,543,009.65**	**1.75**
Smart Thermostat Scenario	Dynamic Peak Pricing	$59,463,767.31	$4,145,453.95	$55,318,313.36	14.34
	Electric Vehicle Charging Stations	$9,822,856.29	$5,739,429.09	$4,083,427.20	1.71
	Charging of Golf Carts Off Peak	$4,327,139.36	$2,421,628.26	$1,905,511.10	1.79
	Thermal Electric Storage- Cooling Rate	$30,497,615.44	$24,492,293.61	$6,005,321.83	1.25

	Controllable Thermostats	$140,614,776.80	$51,521,909.48	$89,092,867.31	2.73
	DLC Electric Water Heaters	$4,176,201.15	$5,471,605.11	-$1,295,403.96	0.76
	DLC Commercial Lighting	$22,637,453.46	$52,793,513.06	-$30,156,059.60	0.43
	Interruptible Rate	$327,556,523.38	$166,874,623.65	$160,681,899.73	1.96
	Program Totals	**$599,096,333.19**	**$313,460,456.22**	**$285,635,876.96**	**1.91**

4.9 RESIDENTIAL DEMAND RESPONSE POTENTIAL

Table 4-14 and Table 4-15 show the residential technical, economic, and achievable potential for both scenarios. Technical potential assumes 100% of eligible customers will participate in all programs starting in year 1, regardless of cost effectiveness. Economic potential includes all programs that are considered cost-effective based on the UCT. Economic potential, like technical potential, assumes that 100% of eligible customers will participate in programs starting in year 1. Achievable potential includes all cost-effective programs. However, achievable potential includes a participation rate to estimate the amount of customers that are realistically expected to participate, and the load they will reduce. These values are at the customer meter.

Table 4-14: Summary of Residential Base Case Technical, Economic and Achievable Potential

Potential Level	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Technical	1,608	1,472	1,386	1,302
Economic	1,367	1,342	1,312	1,278
Achievable	283	367	446	520

Table 4-15: Summary of Residential Smart Thermostat Scenario Technical, Economic and Achievable Program Potential

Potential Level	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Technical	2,265	2,061	1,910	1,763
Economic	2,023	1,931	1,836	1,740
Achievable	296	429	545	616

Table 4-16 shows the residential achievable potential for each program for the years 2020, 2025, 2030, 2035. Those residential programs that are not listed were found to be not cost effective, and therefore have no achievable potential.

Table 4-16: Summary of Achievable Residential Summer MW Savings by Program

Scenario	DR Program	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Base Case	Dynamic Peak Pricing Rate	88	172	251	325
	DLC of Central AC by Switch	195	195	195	195
	TOTAL	**283**	**367**	**446**	**520**
Smart Thermostat Scenario	Dynamic Peak Pricing Rate	88	172	251	325
	DLC of Central AC by Switch	195	195	195	195
	DLC of Central AC by Controllable Thermostat	14	62	99	96
	TOTAL	**296**	**429**	**545**	**616**

4.10 Non-Residential Demand Response Potential

Table 4-17 and Table 4-18 show the non-residential technical, economic, and achievable potential for both scenarios.

Table 4-17: Summary of Non-Residential Base Case Technical, Economic and Achievable Potential

Potential Level	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Technical	3,019	2,991	2,942	2,907
Economic	2,660	2,676	2,673	2,683
Achievable	502	581	661	744

Table 4-18: Summary of Non-Residential Smart Thermostat Case Technical, Economic and Achievable Potential

Potential Level	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Technical	3,638	3,550	3,435	3,337
Economic	3,278	3,234	3,166	3,113
Achievable	549	664	772	873

Table 4-19 shows the non-residential achievable potential for each program for the years 2020, 2025, 2030, 2035. Those non-residential programs that are not listed were found to be not cost effective, and therefore have no achievable potential.

Table 4-19: Summary of Achievable Non-Residential Summer MW Savings by Program

Scenario	Demand Response Measure	2020 Potential (MW)	2025 Potential (MW)	2030 Potential (MW)	2035 Potential (MW)
Base Case	Dynamic Peak Pricing Rate	46	93	139	185
	Special Rate for Electric Vehicles	9	13	21	30
	Special Rate for Golf Cart Charging	3	7	10	14
	Special Rate for Thermal Electric Storage- Cooling	24	48	71	95
	Interruptible Rate	420	420	420	420
	TOTAL	**502**	**581**	**661**	**744**
Smart Thermostat Scenario	Dynamic Peak Pricing Rate	46	93	139	185
	Special Rate for Electric Vehicles	9	13	21	30
	Special Rate for Golf Cart Charging	3	7	10	14
	Special Rate for Thermal Electric Storage- Cooling	24	48	71	95
	DLC of Central AC by Controllable Thermostat	46	84	111	129
	Interruptible Rate	420	420	420	420
	TOTAL	**549**	**664**	**772**	**873**

4.11 Cost of Acquiring Additional DR Potential

Table 4-20 and Table 4-21 show the achievable program costs for each scenario. The current DR budget for DTE is $6.6 million. DTE will need an increased budget to be able to attain the full achievable potential.

Table 4-20: Summary of Achievable Potential Budget Requirements – Base Case

	Residential Achievable Potential Cost	C&I Achievable Potential Cost	Total Achievable Potential Cost	Current Annual Spending Level	Total Additional Budget Requirement
2016	$7,704,175.07	$3,830,841.06	$11,535,016.13	$6,600,000	$4,935,016.13
2017	$7,970,231.34	$3,325,404.32	$11,295,635.66	$6,600,000	$4,695,635.66
2018	$8,189,620.24	$3,374,567.11	$11,564,187.35	$6,600,000	$4,964,187.35
2019	$8,410,569.02	$3,414,712.67	$11,825,281.69	$6,600,000	$5,225,281.69
2020	$8,633,283.10	$3,457,008.45	$12,090,291.55	$6,600,000	$5,490,291.55

2021	$8,861,272.64	$3,496,433.39	$12,357,706.03	$6,600,000	$5,757,706.03
2022	$9,095,548.18	$3,627,647.66	$12,723,195.84	$6,600,000	$6,123,195.84
2023	$9,335,025.50	$3,603,074.93	$12,938,100.44	$6,600,000	$6,338,100.44
2024	$9,577,471.09	$3,655,009.16	$13,232,480.24	$6,600,000	$6,632,480.24
2025	$9,821,419.37	$3,722,961.98	$13,544,381.35	$6,600,000	$6,944,381.35
2026	$9,907,181.22	$3,958,878.73	$13,866,059.95	$6,600,000	$7,266,059.95
2027	$9,942,299.20	$4,057,559.55	$13,999,858.75	$6,600,000	$7,399,858.75
2028	$10,003,030.22	$4,116,292.09	$14,119,322.32	$6,600,000	$7,519,322.32
2029	$10,064,095.08	$4,287,882.14	$14,351,977.22	$6,600,000	$7,751,977.22
2030	$10,125,642.92	$4,348,369.53	$14,474,012.45	$6,600,000	$7,874,012.45
2031	$10,189,308.29	$4,470,528.22	$14,659,836.51	$6,600,000	$8,059,836.51
2032	$10,252,836.24	$4,574,206.31	$14,827,042.55	$6,600,000	$8,227,042.55
2033	$10,318,593.51	$4,686,098.88	$15,004,692.39	$6,600,000	$8,404,692.39
2034	$10,388,107.15	$4,805,512.28	$15,193,619.43	$6,600,000	$8,593,619.43
2035	$10,459,663.46	$4,916,232.34	$15,375,895.80	$6,600,000	$8,775,895.80

Table 4-21: Summary of Achievable Potential Budget Requirements – Smart Thermostat Scenario

	Residential Achievable Potential Cost	C&I Achievable Potential Cost	Total Achievable Potential Cost	Current Annual Spending Level	Total Additional Budget Requirement
2016	$8,394,975.22	$9,298,128.10	$17,693,103.31	$6,600,000	$11,093,103.31
2017	$8,429,979.22	$8,385,020.54	$16,814,999.76	$6,600,000	$10,214,999.76
2018	$8,865,048.03	$8,251,425.49	$17,116,473.52	$6,600,000	$10,516,473.52
2019	$9,399,080.27	$8,108,355.70	$17,507,435.97	$6,600,000	$10,907,435.97
2020	$10,064,698.39	$7,968,350.86	$18,033,049.25	$6,600,000	$11,433,049.25
2021	$10,897,250.57	$7,821,076.29	$18,718,326.86	$6,600,000	$12,118,326.86
2022	$11,914,437.59	$7,923,748.82	$19,838,186.41	$6,600,000	$13,238,186.41
2023	$13,095,606.35	$7,578,272.99	$20,673,879.34	$6,600,000	$14,073,879.34
2024	$14,364,654.45	$7,443,994.48	$21,808,648.94	$6,600,000	$15,208,648.94
2025	$15,597,957.09	$7,326,869.02	$22,924,826.12	$6,600,000	$16,324,826.12
2026	$16,531,682.37	$12,250,705.18	$28,782,387.55	$6,600,000	$22,182,387.55
2027	$17,118,936.28	$11,979,525.54	$29,098,461.81	$6,600,000	$22,498,461.81
2028	$17,505,409.36	$11,617,563.57	$29,122,972.93	$6,600,000	$22,522,972.93
2029	$17,688,824.76	$11,544,035.72	$29,232,860.48	$6,600,000	$22,632,860.48
2030	$17,734,320.13	$11,179,569.00	$28,913,889.13	$6,600,000	$22,313,889.13
2031	$17,700,274.80	$10,956,520.51	$28,656,795.31	$6,600,000	$22,056,795.31
2032	$17,631,673.10	$10,834,085.24	$28,465,758.34	$6,600,000	$21,865,758.34
2033	$17,629,376.02	$10,443,735.88	$28,073,111.90	$6,600,000	$21,473,111.90
2034	$17,591,496.04	$10,198,775.11	$27,790,271.15	$6,600,000	$21,190,271.15

2035	$17,531,552.93	$9,925,801.45	$27,457,354.38	$6,600,000	$20,857,354.38

APPENDIX A | LIST OF DEMAND RESPONSE MEASURES AND PROGRAMS FOR CONSIDERATION BY DTE ENERGY

Demand Response Option	Description	Load Impact		Residential	Non-Residential
Demand Response Definition	Technologies that can be used to reduce electrical consumption for relatively short durations at the end-use customer level in response to peak load conditions, high energy prices, system resource capacity needs, or system reliability events.	Load Shift	Peak Clipping		
Direct Control Programs					
1. Direct load control of air conditioners	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle)	X		X	X
2. Direct load control of electric water heaters	The water heater is remotely shut off by the system operator for periods normally ranging from 2 to 8 hours	X		X	X
3. Direct load control room air conditioners	The compressor of the air conditioner is remotely shut off (cycled) by the system operator for periods that may range from 7 ½ to 15 minutes during every 30-minute period (i.e., 25%-50% duty cycle)	X		X	
4. Direct load control of both air conditioner and water heater	Operations same as AC and WH above. Achieve economies of one trip to premise to install two (2) switches controlling two end-uses. Other reasons for combination?	X		X	
5. Special Rate for Electric Thermal Storage – Cooling	The use of a cold storage medium such as ice, chilled water, or other liquids. Off-peak energy is used to produce chilled water or ice for use in cooling during peak hours. The cool storage process is limited to off-peak periods	X			X

Demand Response Option	Description	Load Impact		Residential	Non-Residential
Demand Response Definition	Technologies that can be used to reduce electrical consumption for relatively short durations at the end-use customer level in response to peak load conditions, high energy prices, system resource capacity needs, or system reliability events.	Load Shift	Peak Clipping		
Direct Control Programs					
6. Control of swimming pool pumps, water garden pumps, hot tubs pumps and heating elements	The swimming pool pump is remotely shut off by the system operator for periods normally ranging from 2 to 4 hrs		X	X	
7. Direct load control of commercial lighting - On/Off, Dimming	The lighting load is remotely shut off by the system operator for periods normally ranging from 2 to 4 hours		X		X
8. Controllable "Smart" Thermostats	The system operator can remotely raise the AC's thermostat setpoint during peak load conditions, lowering AC and/or heating load. Consideration of utility control should address customer control capabilities including the Nest Learning Thermostat as well as services provided by ISPs, home security cos.	X		X	X
Distributed Generation					
9. Existing customer-owned diesel generation	Customer-owned generation is operated either remotely by the system operator or by the DGen owner. Does not include solar since not dispatchable		X	X	X
Rate Programs					
10. Interruptible Rate	A discounted rate is offered to the customer for agreeing to interrupt or curtail load during peak period. The interruption is mandatory. No buy-through options are available.	X	X		X

Demand Response	Description	Load Impact	Residential	Non-Residential

Option		Load Shift	Peak Clipping		
Demand Response Definition	Technologies that can be used to reduce electrical consumption for relatively short durations at the end-use customer level in response to peak load conditions, high energy prices, system resource capacity needs, or system reliability events.				
11. Dynamic Pricing Rate	A retail rate with different prices for usage during different blocks of time. Daily pricing blocks could include on-peak, mid-peak, and off-peak periods. Pricing is pre-defined, and once established do not vary with actual cost conditions. Dynamic pricing includes time of use rates, critical peak pricing rates, and real-time pricing rates.	X	X	X	X
12. Special Rate for Golf Cart Charging	Special rate service for golf courses that charge electric golf carts off-peak		X		X
13. Special Rate for Electric Vehicles	Special rate service for electric vehicles that charge off-peak		X	X	X

APPENDIX B | PARTICIPATION RATES

Table B-1: Residential Central Air Conditioning Direct Load Control Program Participation Rates for Other Utilities

Source: GDS Survey

Utility	DLC AC Participating Customers	Eligible Customers	Participation Rate	Data Year
Dakota Electric Association	33,000	61,875	53.33%	2015
PEPCO	N/A	N/A	53.00%	2013
SMECO	36,500	70,200	51.99%	2015
BG&E	349,758	924,000	37.85%	2013
DPL	N/A	N/A	37.00%	2013
NOVEC	35,000	121,500	28.81%	2015
Public Service Company of New Mexico	36,611	130,500	28.05%	2015
Rappahannock Electric Coop	10,500	47,200	22.25%	2015
Sacramento Municipal Utility District	94,227	427,440	22.04%	2015
Connexus Energy	22,000	102,300	21.51%	2015
DTE Electric Co.	277,186	1,439,815	19.25%	2015
Interstate Power and Light Co	50,000	300,000	16.67%	2015
PECO	97,600	903,704	10.80%	2012
Dairyland Power Cooperative	16,896	169,216	9.98%	2013
PPL	42,000	700,000	6.00%	2012
FE: Met-Ed	21,369	410,942	5.20%	2012
Georgia Power	62,411	1,352,233	4.62%	2013
FE: Penelec	11,860	348,824	3.40%	2012
FE: Penn Power	2,806	87,688	3.20%	2012
Duquesne	1,491	331,333	0.45%	2012
TOTAL	**1,201,215**	**7,928,769**	**21.77%**	**N/A**

Table B-2: Non-Residential Dynamic Pricing Participation Rates (Excludes Opt –Out and Mandatory) Top 25
Source: FERC 2012 Demand Response Survey Data

Utility/State	Participation Rate
Sierra Electric Cooperative, Inc./NM	100.0%
Itasca-Mantrap Cooperative Electrical Association/MN	30.7%
Adams Electric Cooperative/IL	21.1%
Grand Haven Board of Light and Power/MI	17.3%
Progress Energy Carolinas/NC	13.5%
Los Angeles Department of Water and PowerCA	12.6%
Progress Energy Carolinas/SC	11.1%
Salt River Project Agricultural Improvement & Power District/AZ	9.0%

Colorado Springs Utilities/CO	7.9%
Interstate Power and Light Company/IA	7.2%
Otter Tail Power Company/SD	6.4%
Progress Energy Florida/FL	5.6%
Tampa Electric Company/FL	5.0%
OGE Energy Corporation/OK	4.7%
Hustisford Utilities/WI	4.4%
Riverside Public Utilities/CA	4.3%
Carbon Power & Light Inc/WY	4.1%
Virginia Electric & Power Co/NC	3.9%
Otter Tail Power Company/MN	3.8%
Rice Lake Utilities/WI	3.7%
City of Carlyle, Illinois/IL	3.5%
City of Carmi, Illinois/-IL	3.5%
United Power/CO	3.3%
City of Pasadena/CA	3.0%
New Holstein Public Utility/WI	3.0%

Table B-3: Non-Residential Dynamic Pricing Participation Rates (includes Opt-in and Opt-out) Top 25

Source: Energy Information Administration (EIA) Form 861 Data (2014)

Utility	State	Participation Rate
Southern California Edison Co	CA	100.0%
Southwestern Electric Power Co	AR	98.6%
Public Service Co of Oklahoma	OK	94.6%
Sacramento Municipal Util Dist	CA	91.8%
Pacific Gas & Electric Co	CA	57.8%
Constellation Energy Services, Inc.	ME	55.3%
Constellation Energy Services, Inc.	MA	52.5%
Constellation Energy Services NY, Inc.	NY	44.1%
Constellation Energy Services, Inc.	NH	30.7%
United Illuminating Co	CT	28.3%
Northern States Power Co	WI	24.2%
Los Angeles Department of Water & Power	CA	21.5%
Delmarva Power	DE	21.3%
Madison Gas & Electric Co	WI	21.0%
Wisconsin Electric Power Co	WI	17.7%
San Diego Gas & Electric Co	CA	17.6%
Duke Energy Progress - (NC)	NC	14.3%

Utility	State	Participation Rate
Wisconsin Public Service Corp	WI	13.7%
Duke Energy Progress - (NC)	SC	11.2%
Salt River Project	AZ	11.2%
Southwestern Electric Power Co	TX	10.3%
Oklahoma Gas & Electric Co	OK	7.6%
Wisconsin Power & Light Co	WI	7.5%
Southwestern Electric Power Co	LA	7.0%
Duke Energy Carolinas, LLC	NC	6.7%

Table B-4: Non-Residential Direct Load Control Participation Rates
Top 25
Source: FERC 2012 Demand Response Survey Data

Utility/State	Participation Rate
Caddo Electric Cooperative, Inc./OK	61.5%
Douglas Electric Cooperative, Inc./SD	50.0%
FARMERS' ELECTRIC COOPERATIVE, INC./MO	39.9%
Midwest Electric, Inc./OH	25.0%
CITY OF BIG STONE CITY/SD	24.5%
Power Choice/ Pepco Energy Serv/PA	20.0%
Pee Dee Electric Membership Corp./NC	18.8%
Otter Tail Power Company/ND	18.7%
Dairyland Power Cooperative/MN	18.1%
City of Wadena Electric & Water/MN	16.2%
Otter Tail Power Company/MN	15.3%
Otter Tail Power Company/SD	14.8%
Barnesville Municipal Electric/MN	13.7%
Dairyland Power Cooperative/IA	11.2%
City of East Grand Forks/MN	10.1%
Xcel Energy/ND	7.5%
McLean Electric Coop/ND	7.5%
Renville-Sibley Cooperative Power Association/MN	6.3%
Ames, City of/IA	6.1%
Southern Indiana Gas & Elec Co dba Vectren Energy Delivery of Indiana/IN	5.6%
Florida Power & Light Company/FL	5.5%
Marshall Municipal Utilities/MN	5.2%
Louisville Gas & Electric and Kentucky Utilities/KY	4.0%
Dairyland Power Cooperative/WI	3.6%
San Diego Gas & Electric/CA	3.4%

Table B-5: Non-Residential Demand Response Program Participation Rates From Other Recent DR Potential Studies

Program Name	Opt In Participation Rate	Sector	Enabling Technology?	Beginning Year	Year Achieved	Source
CPP	19.0%	Small C&I	No	2016	2028	Demand Response (DR) Market Potential in Xcel Energy's Northern States Power Service Territory, Brattle Group and YouGov America, April 2014.
	22.0%	Small C&I	Yes	2016	2028	
	20.0%	Medium C&I	No	2016	2028	
	22.0%	Medium C&I	Yes	2016	2028	
	22.0%	Large C&I	No	2016	2028	
	25.0%	Large C&I	Yes	2016	2028	
All Comm. DR Programs	15.0%	All Commercial	Not Stated	2015	2030	Assessing DR Program Potential for the Seventh Power Plan, UPDATED FINAL REPORT, Northwest Power and Conservation Council, Navigant Consulting, January 19, 2015.
All Industrial DR Programs	25.0%	All Industrial	Not Stated	2015	2030	
CPP	15.0%	All C&I	Not Stated	2020	2024	PacifiCorp Demand-Side Resource Potential Assessment for 2015-2034, Applied Energy Group, January 30, 2015.
	20.0%	Medium and Large C&I	Not Stated	2019	2028	An Assessment of PGE's DR Potential, Brattle Group, 2012.
All Dynamic Pricing	10.0%	All C&I	All	2009	2020	Assessment of DR and Energy Efficiency (EE) Potential for Midwest ISO, Global Energy Partners, LLC, July 2010.
All C&I Pricing Programs	10.0%	All C&I	All	2010	2020	Assessment of DR and EE Potential, Volume 2 Eastern Interconnection Analysis, Global Energy Partners, LLC, November 2010.
Direct Load Control – Central AC	53.0%	Medium C&I	Yes	2016	2028	Demand Response (DR) Market Potential in Xcel Energy's Northern States Power Service Territory, Brattle Group and YouGov America, April 2014.
DLC – All End Uses	20.0%	Small C&I	Yes	2015	2025	An Assessment of PGE's DR Potential, Brattle Group, 2012.
	18.0%	Medium & Large C&I				

APPENDIX C | LOAD REDUCTION SOURCES AND EXPLANATION OF CALCULATIONS

Residential Load Reduction Sources

Table C-1: Residential Load Reduction Sources

DR Option	Source
Time of Use Rate	FERC 2012
Dynamic Peak Pricing Rate	DTE SmartCurrents Report, Table 27
Direct load control of central air conditioners	DTE
Direct load control of swimming pool pumps, water garden pumps, hot tubs pumps and heating elements	Southern California Edison Pool Pump Demand Response Potential Report 2008
Direct load control of controllable thermostats	DTE SmartCurrents Report, Table 27
Direct load control of room air conditioners	GDS Research
Direct load control of water heaters	RLW Analytics Deemed Savings Estimates for PJM Region 2007

Residential Load Reduction Calculations for Rate Program

To calculate the DPP kW savings, GDS took the average of the impact for peak hours (3-7 pm) in DTE's pilot DPP program. GDS used the DPP group with the highest savings in DTE's pilot program, T3 (rate and programmable controllable thermostat).

Table C-2: Peak Impact for DPP Pilot Program

Hour Ending	Impact (kW)
15	0.389
16	0.684
17	0.705
18	0.668
Average	**0.612**

Non-Residential Load Reduction Sources

Table C-3: Sources of Non-Residential Load Reduction Assumptions

DR Option	Sources
Dynamic Peak Pricing	2012 FERC Survey Data FERC Demand Response Model – Assumptions for the State of Michigan
Electric Vehicle Charging Stations Off Peak	Report On Electric Vehicle Charging, Florida Public Service Commission, Table 4 - Charger Level Classifications, December 2012 DTE Energy Plug-In Electric Vehicles and Infrastructure, Presentation by Hawk Asgeirsson, P.E. Manager -Power Systems Technologies DTE Energy, asgeirssonh@dteenergy.com
Charging of Golf Carts Off Peak	Eaton Corporation, Golf Course Energy Management Solutions, Eaton's Pow-R-Command Golf Car Off-Peak Charging Brochure Demand Response and Load Management Strategies for Electric Forklifts and Non-Road EV Fleets Richard Cromie Program Manager Southern California Edison Co.
Thermal Electric Storage- Cooling Rate	Michigan Commercial Baseline Study, Prepared for the Michigan Public Service Commission by Cadmus and Opinion Dynamics, July 2011
DLC Central AC by Switch	Michigan Commercial Baseline Study, Prepared for the Michigan Public Service Commission by Cadmus and Opinion Dynamics, July 2011
DLC Electric Water Heaters	2012 FERC Survey Data Michigan Energy Measures Database (MEMD
DLC Commercial Lighting	Business Energy Advisor/E Source, Strategies for C&I Demand Response LIGHTING CALIFORNIA'S FUTURE: COST-EFFECTIVE DEMAND RESPONSE, Prepared For: California Energy Commission By: NEV Electronics, LLC, California Lighting Technology Center, March 2011 Lighting Controls Association, Lighting Control and Demand Response, By Craig DiLouie, on May 20, 2014 Demonstration and Evaluation of lighting technologies and Applications, Lighting Research Center, Field Test Issue 6, October 2011 What is the relation between energy consumption savings and peak load savings and how can this affect future energy conservation requirements? - Study conducted by the City of Toronto.
Interruptible Rate	Data provided by DTE

Non-Residential Load Reduction Calculations

Dynamic Peak Pricing

The assumed load reduction factor of 14% of total participant coincident peak load is based on a GDS review of:

- Dynamic pricing load reduction assumptions for Michigan in the FERC Demand Response Model (with enabling technology). Customers with loads suitable for enabling technology are considered the most likely to participate.

Table C-4: Non-Residential FERC DR Model Savings Assumptions for Michigan

AVERAGE PARTICIPANT CRITICAL DAY LOAD AND LOAD REDUCTIONS	Residential w/o Central A/C	Residential w/ Central A/C	Commercial & Industrial Small	Commercial & Industrial Medium	Commercial & Industrial Large
Critical peak avg. hourly load (kW)	0.93	1.85	6.18	48.07	608.74
Customers on dynamic pricing without enabling tech (% reduction)	8.5%	19.3%	0.7%	8.7%	7.5%
Customers on dynamic pricing with enabling tech (% reduction)	DNA	33.8%	14.9%	13.9%	13.9%
Automated or Direct Load Control DR (kW reduction)	DNA	0.46	2.19	6.58	32.90
Interruptible Tariffs - (% reduction)	0.0%	0.0%	0.0%	100.0%	48.6%
Other DR (% reduction)	0.0%	0.0%	0.0%	39.4%	100.0%

Savings calculated from the 2012 FERC Demand Response Survey Data for Time-of-Use (TOU) rate programs.

Table C-5: Non-Residential TOU Savings Factors from Other Utilities

Utility	Realized Deemed Reduction (MW)	Max Demand (MW)
OGE Energy Corporation	33.02	948.10
OGE Energy Corporation	73.94	598.29
Mississippi Power	11.66	208.00
Tennessee Valley Authority	92.00	144.00
OGE Energy Corporation	26.43	67.31
MECKLENBURG ELECTRIC COOPERATIVE	24.10	35.40
City of Glendale	0.20	16.00
Grand River Dam Authority	10.00	15.00
Maui Electric Company, Limited	3.08	10.70
Tennessee Valley Authority	6.00	10.00
A & N Electric Cooperative	0.01	9.17
Board of Public Utilities, City of McPherson	0.50	7.10
Butler Rural Electric Cooperative Association, Inc.	0.25	5.40
McLeod Cooperative Power Association	0.80	4.70
Linn County Rural Electric Cooperative Association	1.00	3.88
Dixie Escalante REA Inc.	3.00	3.50
Empire Electric Association, Inc.	2.00	3.00
Poudre Valley Rural Electric Association, Inc.	0.58	2.27

Utility	Realized Deemed Reduction (MW)	Max Demand (MW)
United Power	1.80	1.80
Otero County Electric Cooperative, Inc.	0.19	1.57
Adams Electric Cooperative, Inc.	0.80	1.30
OGE Energy Corporation	0.38	0.97
Jackson Electric Membership Corporation	0.25	0.88
Sierra Electric Cooperative, Inc.	0.08	0.78
United Electric Cooperative Services, Inc.	0.18	0.55
BURLINGTON ELECTRIC DEPARTMENT	0.25	0.38
Crow Wing Cooperative Power & Light Company	0.17	0.21
Linn County Rural Electric Cooperative Association	0.18	0.18
Clay Electric Cooperative, Inc.	0.10	0.10
Clay Electric Cooperative, Inc.	0.10	0.10
Okefenoke Rural El Member Corp	0.10	0.10
Jemez Mountains Electric Cooperative, Inc.	0.01	0.01
Total	**2100.75**	**293.16**
Savings Factor	14%	

Savings calculated from the 2012 FERC Demand Response Survey Data for Critical Peak Pricing (CPP) rate programs.

Table C-6: Non-Residential CPP Savings Factors from Other Utilities

Utility	Realized Deemed Reduction (MW)	Max Demand (MW)
Butler Rural Electric Cooperative, Inc.	3.10	3.20
Canadian Valley Electric Cooperative	43.36	72.18
Clay Electric Cooperative, Inc.	16.00	22.20
Green Mountain Power Corporation	3.00	5.00
High Plains Power, Inc.	5.00	48.80
Jackson Electric Membership Corporation	9.40	12.00
OGE Energy Corporation	2.74	4.09
Rayle Electric Membership Corporation	1.00	10.00
Red River Valley Rural Electric Association	1.70	2.00
Richmond Power and LIght	4.58	61.71
Rural Electric Cooperative, Inc.	0.50	1.00
Southern California Edison (SCE)	35.00	671.11
Town of High Point	2.90	11.90
United Power	2.80	2.80
Wisconsin Public Service Corporation	8.36	100.64
Total	139.44	1028.63

Savings Factor	14%

Electric Vehicle Charging Stations Off-Peak

GDS estimated the full non-coincident charging load for plug-in electric vehicles (PEVs) based on the following charger level load data from a Florida Public Service Commission Report cited above in Table C-5. Weights were then applied to public and private chargers based on the actual number of PEVs on the road and actual data on public PEV charging stations in Michigan. Data sources for the weights shown in Table C-7 are:

- U.S. Energy Information Administration (EIA), Annual Energy Outlook 2015, Reference Case, 40. -Light-Duty Vehicle Stock by Technology Type, April 2015.
- Deployment Rollout Estimate of Electric Vehicles, 2011-2015, by Center for Automotive Research, Ann Arbor, Michigan, January 2011.
- U.S. Department of Energy, Energy Efficiency and Renewable Energy, Alternative Fuels data Center, Alternative Fueling Station Locator.
- EIA, Form 861 Data, Sales to Ultimate Customers by Utility, 2014. (Percent of Michigan residential customers in DTE service area was used to allocate a portion of the estimated number of state PEVs to the DTE service area)

Table C-7: Estimate of per PEV Charging Load

Source: National Electrical Code Article 625

Charger Level	Load	Charge Time	Voltage in Alternating Current (VAC)	Public Charging - Percent by Charger Level	Average kW	Weighted Average (kW)	Count (2015)	Weight
Level 1 (Home)	1.1-1.8 kW	6-10 hours	120	21%	1.45	0.311	N/A	N/A
Level 2 (Home and Work)	3.3 kW	3-4 hours	208/240	75%	8.1	6.054	N/A	N/A
Level 2+ (Home and Work)	6.6-19.2 kW	30 mins – 2 hours	N/A	N/A	N/A	N/A	N/A	N/A
Level 3 (Recharging Station)	50-150 kW	15-30 minutes	480	4%	100	3.818	N/A	N/A
Totals								
Public Chargers	10.183				681		0.19	
Home Chargers (Average of Level 1 and 2)	4.775				2943		0.81	
Total Public & Home Chargers	5.79				3624			

Coincident factors of .45 for a flat rate and .17 for a TOU rate were then applied to the above non-coincident average charging load estimate. The difference (1.62 kW) between these two calculated coincident peak values is the savings reduction for off peak PEV charging that is assumed in this study. The source of the coincident factors is the DTE presentation cited above in Table C-5.

Charging of Golf Carts Off-Peak

The potential reduction for off peak charging of golf carts assumes a .75kw diversified demand per golf cart and an average of 75 golf carts per golf course.

Thermal Electric Storage- Cooling Rate

GDS used site survey data from the 2011 Michigan Commercial Baseline Study to determine the average central air conditioning coincident peak demand per commercial building. The calculation is as follows:

Average Commercial Tons of AC Per Building	10.63
Average Peak kW Use Per Building	12.76
Coincidence Factor	0.81
Coincident Average Peak kW Use Per Building	10.33

The coincident factor is based on TRM coincidence factors from states with similar CDD (NY and CT)

DLC Central AC by Switch

A 50% cycling strategy is assumed. The coincident average peak of 10.33 kW (See TES – Cooling Rate) is reduced by 50%, resulting in a 5.16 kW load reduction per participant.

DLC Electric Water Heaters

For DLC of electric water heating the reduction per controlled water heater is based on the following data from the 2012 FERC DR Survey and the Michigan Energy Measures Database (MEMD)

Table C-8: Non-Residential Water Heater DLC Savings from Other Utilities

Utility	Number of Program Participants	Realized Program Demand Reduction (MW)	Demand Reduction Per Participant (kW)
City of East Grand Forks - (MN)	19	0.029	1.5
Dairyland Power Cooperative	4590	3.900	0.8
FARMERS' ELECTRIC COOPERATIVE, INC.	448	0.400	0.9
Marshall Municipal Utilities	80	0.056	0.7
McLean Electric Coop	34	0.100	2.9
Otter Tail Power Company	481	0.377	0.8
City of East Grand Forks - (MN)	6030	5.662	0.9
Total	**11682**	**10.524**	**0.9**

The MEMD for the Commercial Water Heaters contains the following commercial water heating assumptions for existing water heaters:

Table C-9: Commercial Water Heating Assumptions for Existing Water Heaters

	Electric Storage (≤ 55 gallons)	Electric Storage (> 55 gallons)
Assumed Storage Capacity (gal)	50	80
Hot Water Used (Gallons per Day)	117	117
Days of Operation Per Year	365	365
Temperature of Hot Water (F)	135	135
Temperature of Cold Water Supply (F)	54.5	54.5
Efficiency	0.95 EF	1.97 EF
Annual Hours	3,680	3,680
Average Existing kWh/yr	8,845	4,265
CF	0.5	0.5

The coincident demand for Electric Storage (≤ 55 gallons) is:

(8845 kWh/yr./3680 Annual Hours) * .5 CF = 1.2kW

The coincident demand for Electric Storage (> 55 gallons):

(4265 kWh/yr./3680 Annual Hours) * .5 CF = .579 kW

The average of the above two coincident demand values is .89 kW

DLC Commercial Lighting

GDS used the following multiple data sources to develop an estimate of potential per participant lighting demand reduction as a percent of total participant demand:

Table C-10: Data Sources for DLC Commercial Lighting

Savings Factor	Notes	Source	Impact (% of total demand)	Sector Weight From MI Potential Study	Sector	Weighted Savings %
Up to 5% of overall building load	Curtailing lighting. Facility operators can curtail lighting in special-purpose rooms, such as cafeterias and lounges, when they are unoccupied. Operators can also reduce lighting in corridors. Rooms and corridors can use natural lighting if available. On average, reducing lighting loads in common areas, such cafeterias and lounges, can reduce a building's peak load by up to 5 percent.	Business Energy Advisor/E Source	5.00%	5.23%	Health	0.30%

Savings Factor	Notes	Source	Impact (% of total demand)	Sector Weight From MI Potential Study	Sector	Weighted Savings %
Up to 20% of overall building load	Curtailing lighting. Lighting can be turned off in special-purpose rooms such as cafeterias, auditoriums, and recreational facilities, as well as in selected hallways and other areas during DR events. In addition, overhead lights in occupied areas can be selectively turned off, with occupants relying on task lamps if necessary. Office buildings can use dimming ballasts to dim the lights—studies show that building occupants usually cannot detect lighting level reductions of up to 20 percent. Turning off lights also reduces cooling loads, which can provide demand relief during the summer.	Business Energy Advisor/E Source	20.00%	29.24%		5.80%
Up to 5% of overall building load	Curtailing lighting. Hotels and motels typically have discretionary lighting loads or decorative lighting in the atrium, conference rooms, and meeting rooms that hotel staff can turn off during a DR event. Staff can also turn off lighting in special-purpose rooms like restaurants, conference rooms, and exercise facilities. On the morning of a DR event, facility managers can also remind staff to turn off lights in unoccupied areas and guest rooms. On DR event days, the staff can reiterate that policy to the housekeeping staff. Turning off lights can reduce a hotel's total peak load by up to 5 percent.	Business Energy Advisor/E Source	5.00%	3.30%	Lodging	0.20%

Savings Factor	Notes	Source	Impact (% of total demand)	Sector Weight From MI Potential Study	Sector	Weighted Savings %
5% - 15% of overall building load	Turning off lights. Although retailers are very concerned about lighting their products, they can still use a couple of strategies to reduce lighting loads. First, they can use natural lighting if products are placed near exterior windows. The store may also turn off a portion of its lights or turn off every other row of lights. Finally, during DR events, store staff can turn lights off in special-purpose areas, such as window displays, stockrooms, offices, and other peripheral rooms. You can conduct lighting strategies manually or through a BAS. Turning off lights can reduce overall building demand by 5 to 15 percent	Business Energy Advisor/E Source	10.00%	10.65%	Retail	1.10%
5% - 8% of overall building load	Turning off lights. Although grocery stores are concerned about lighting their product, they can still use a couple of strategies to reduce lighting loads. First, the store can reduce lighting loads by turning off every other row of lights. Staff can also turn off lighting in special-purpose areas, such as window displays, stockrooms, offices, and other peripheral rooms. These strategies can be conducted either manually or through a BAS. Turning off lights can typically reduce a grocery store's total peak load by 5 to 8 percent (Table 1). In New York, for example, a grocery store with a total peak load of 375 kilowatts (kW) reduced its peak load by 30 kW by turning off one-third of its lights.	Business Energy Advisor/E Source	6.50%	5.86%	Grocery Stores	0.40%

Savings Factor	Notes	Source	Impact (% of total demand)	Sector Weight From MI Potential Study	Sector	Weighted Savings %
7% - 10% of total demand	As a demand response device, Cost-Effective Demand Response significantly reduces peak demand. Initial estimates indicate that 20 to 30 percent of the building's lighting demand, or 7 to 10 percent of total demand, can be shed and maintained off during the demand response event.	LIGHTING CALIFORNIA'S FUTURE: COST-EFFECTIVE DEMAND RESPONSE, Prepared For: California Energy Commission By: NEV Electronics, LLC, California Lighting Technology Center, March 2011	8.50%	45.70%	All Other Sectors	3.90%
Total Weighted Average						**11.6%**
14% - 23% of lighting load	If lighting can be dimmed, a big question is how much can be tolerated before occupants notice the change and find it objectionable. A National Research Council-Institute for Research in Construction (Canada) field study found that lighting loads could be reduced 14-23% without significant numbers of occupants noticing. The Institute subsequently developed recommendations for emergency demand response application in office buildings:	Lighting Controls Association, Lighting Control and Demand Response, By Craig DiLouie, on May 20, 2014	5.7%	100.00%	Toronto End use Study - Lighting = 31% of Commercial Building Peak	
32% of lighting load		Demonstration and Evaluation of lighting technologies and Applications, Lighting Research Center, Field Test Issue 6, October 2011	9.9%		Toronto End use Study - Lighting = 31% of Commercial Building Peak	

Savings Factor	Notes	Source	Impact (% of total demand)	Sector Weight From MI Potential Study	Sector	Weighted Savings %
7% - 10% of total demand	As a demand response device, Cost-Effective Demand Response significantly reduces peak demand. Initial estimates indicate that 20 to 30 percent of the building's lighting demand, or 7 to 10 percent of total demand, can be shed and maintained off during the demand response event.	LIGHTING CALIFORNIA'S FUTURE: COST-EFFECTIVE DEMAND RESPONSE, Prepared For: California Energy Commission By: NEV Electronics, LLC, California Lighting Technology Center, March 2011	8.5%	100.00%		
Average of Gray Cells			8.9%	Of Total Demand		

Interruptible Rate

The potential non-residential interruptible rate demand reduction is held constant at its current level of 420 MW over the entire study period.

APPENDIX D | DEMAND RESPONSE MEASURE ASSUMPTIONS

RESIDENTIAL SECTOR DR Program	Per Unit Installed Cost to DTE	Useful Life (Years)	If existing, # residential participants	Age of existing program	Saturation	Participant Incentive ($/kW-Yr)	Annual # Control Hours	Hierarchy
Dynamic Peak Pricing Rate	$0	10	1,500	5	100%	$0	1,040	1
Direct load control of central air conditioners by switch	$200	10	277,186	45	75%	$40	80	2
Direct load control of central air conditioners by controllable thermostats	$268.72- $261 thermostat, $7.72 installation	10	N/A	N/A	65%	$0	2,080	2
Direct load control of room air conditioners	$200	10	N/A	N/A	28%	$40	80	2
Direct load control of electric water heaters	$200	10	N/A	N/A	14%	$40	80	2
Direct load control of swimming pool pumps, water garden pumps, hot tubs pumps and heating elements	$200	10	N/A	N/A	8%	$40	80	2

Sources

RESIDENTIAL SECTOR DR Program	Per Unit Installed Cost	Useful Life (Years)	If existing, # residential participants	Age of existing program	Saturation	Participant Incentive ($/kW-Yr)	Annual # Control Hours	Hierarchy
Time of use rate	DTE	N/A	N/A	N/A	GDS	DTE	DTE Rate Schedule	DTE
Dynamic peak pricing rate	DTE	N/A	DTE	DTE	GDS	DTE	DTE Rate Schedule	DTE
Direct load control of central air conditioners by switch	DTE	Pennsylvania, Act 129 2013 Order	DTE	DTE	DTE	DTE	DTE	DTE
Direct load control of central air conditioners by controllable thermostats	MEMD	Pennsylvania, Act 129 2013 Order	N/A	N/A	DTE	DTE	DTE, Rate Schedule	DTE
Direct load control of room air conditioners	DTE	Pennsylvania, Act 129 2013 Order	N/A	N/A	DTE	DTE	DTE	DTE
Direct load control of electric water heaters	DTE	Pennsylvania, Act 129 2013 Order	N/A	N/A	DTE	DTE	DTE	DTE
Direct load control of swimming pool pumps, water garden pumps, hot tubs pumps and heating elements	DTE	Pennsylvania, Act 129 2013 Order	N/A	N/A	DTE	DTE	DTE	DTE

COMMERCIAL SECTOR DR Program	Per Unit Installed Cost to DTE	Useful Life (Years)	If existing program, current # participants	Age of existing program (Years)	Eligible Customers	Saturation*	Non-Rate Based Participant Incentive	Annual # Control Hours	Hierarchy
Dynamic Peak Pricing	$0	10	Not Applicable (N/A)	N/A	All secondary service C&I customers	100%	$0	1,040	1
Electric Vehicle Charging Stations Off Peak	$300 (Cost of second meter)	10	2,962	4	Residential and commercial customers desiring separately metered service for the sole purpose of charging licensed electric vehicles	N/A	$0	1,850	N/A
Charging of Golf Carts Off Peak	$0	20	N/A	N/A	Golf Courses	N/A	$4,500	1050	N/A
Thermal Electric Storage-Cooling Rate	$0	20	N/A	N/A	Secondary and primary service commercial customers	94%	$475/kW (One time installation cost incentive payment)	2112	1
DLC Central AC by Switch	$200	10	906	45	Secondary and primary service commercial customers	94%	$42/kW-yr.	80	2
DLC Central AC by Controllable Thermostat	$134.36 per thermostat	10	N/A	N/A	Secondary and primary service commercial customers	94%	$0	80	2
DLC Electric Water Heaters	$200	10	N/A	N/A	This study analyzed DLC of water heating as an addition to the DLC AC program.	94% of Commercial customers have AC	$40/kW-yr.	80	2

COMMERCIAL SECTOR DR Program	Per Unit Installed Cost to DTE	Useful Life (Years)	If existing program, current # participants	Age of existing program (Years)	Eligible Customers	Saturation*	Non-Rate Based Participant Incentive	Annual # Control Hours	Hierarchy
					Due to the complementary nature of the programs, it is assumed that customers must have air conditioners enrolled in the program and have electric water heat to qualify for participation	Systems. Saturation of Electric Water Heating: 88% - Stand Alone Water Heater 43% - Electric			
DLC Commercial Lighting	14.34 per ballast (Assumes T12 would be replaced with T8 without DR option. Cost is to upgrade to load shedding ballast system) Average of approximately 132 eligible ballasts per participant	10	N/A	N/A	Secondary and primary service commercial customers	67%	$40/kW-yr.	80	2
Interruptible Rate	$0	N/A	62	20+ years	Current Interruptible Rate Customers	100%	$0	80	N/A

** 100% saturation for DR rate programs means that the programs have the potential to impact all customer end-uses while saturations for programs that target specific end-uses such as central air conditioning represent the saturation of that end-use.*

Sources

COMMERCIAL SECTOR DR Program	Per Unit Installed Cost to DTE	Useful Life (Years)	If existing program, current # participants	Age of existing program	Eligible Customers	Saturation*	Participant Incentive	Annual # Control Hours	Hierarchy
Dynamic Peak Pricing	DTE - Advanced metering infrastructure (AMI) is already installed)	DTE - Replacement costs for AMI meters after 10 years are not assigned to the program	Not Applicable (N/A)	N/A	DTE Rate Schedule	GDS	GDS	DTE Rate Schedule	DTE
Electric Vehicle Charging Stations Off Peak	DTE	DTE	DTE	DTE	DTE Rate Schedule	N/A	GDS	Assumes additional annual 3,000 kWh for PEV charging. Approximately the energy use for a Chevy Volt. Source: BGE Electric Vehicle Off-Peak Charging Rate Proposal Maryland EVIC Briefing 1-Oct-13.	N/A
Charging of Golf Carts Off Peak	GDS	GDS - System replaces existing electrical Panel(s)	N/A	N/A	GDS	N/A	50% of cost of Eaton's Pow-R-Command golf car off-peak charging system. Source: Eaton Corporation.	Assumes 6 charging hours per day for 175 days per year. Source: Eaton Corporation	N/A

COMMERCIAL SECTOR DR Program	Per Unit Installed Cost to DTE	Useful Life (Years)	If existing program, current # participants	Age of existing program	Eligible Customers	Saturation*	Participant Incentive	Annual # Control Hours	Hierarchy
Thermal Electric Storage-Cooling Rate	GDS	Ice, ice energy: The hot market for cooled liquid energy storage Ice Energy and CALMAC are proving their value while newer technologies wrestle with cost, By Herman K. Trabish, November 3, 2015.	N/A	N/A	GDS	2013 DTE Commercial Baseline Study	Statewide Permanent Load Shifting Program Design Proposal with Revised Cost-Effectiveness Analysis Letter to CA PUC, May 21, 2013. Used average of highest and lowest incentive.	GDS Calculation – Assumes 8 hours per day, 22 days per month	GDS
DLC Central AC by Switch	DTE	GDS - 10 year lifespan of switching equipment is a standard assumption in the industry.	DTE	DTE	GDS	2013 DTE Commercial Baseline Study	GDS – Review of other utility commercial AC DLC programs: Xcel Energy TECO Wisconsin Public Service Corp. Public Service New Mexico PECO	DTE	GDS

COMMERCIAL SECTOR DR Program	Per Unit Installed Cost to DTE	Useful Life (Years)	If existing program, current # participants	Age of existing program	Eligible Customers	Saturation*	Participant Incentive	Annual # Control Hours	Hierarchy
DLC Central AC by Controllable Thermostat	MEMD (Assumes that DTE pays half of total installed cost)	MEMD (Programmable thermostat – Tier 3)	N/A	N/A	GDS	2013 DTE Commercial Baseline Study	DTE Rate Schedule	DTE	GDS
DLC Electric Water Heaters	DTE	GDS - 10 year lifespan of switching equipment is a standard assumption in the industry.	N/A	N/A	GDS	2013 DTE Commercial Baseline Study	DTE	DTE	GDS
DLC Commercial Lighting	Demonstration and Evaluation of lighting technologies and Applications, Lighting Research Center, Field Test Issue 6, October 2011. 2010 and 2013 DTE Commercial Baseline Studies.	GDS (conservative estimate based on industry range of 10 -15 years)	N/A	N/A	GDS	2010 and 2013 DTE Commercial Baseline Studies.	DTE	DTE	GDS
Interruptible Rate	DTE	N/A	DTE	DTE	DTE	GDS	DTE	DTE	DTE

APPENDIX E | AVOIDED COSTS

	Avoided Energy Costs (Nominal $/MWh)		Avoided Capacity Costs (Nominal $/kW-year)	Avoided T&D Costs
	Peak	Off-Peak		
2015	$34.1350	$26.3227	$3.2883	$0.00
2016	$39.3033	$28.7358	$32.2734	$0.00
2017	$38.8367	$28.3275	$61.5186	$0.00
2018	$40.3075	$28.5983	$67.7610	$0.00
2019	$39.3617	$28.1942	$63.4437	$0.00
2020	$39.7117	$27.8400	$75.9207	$0.00
2021	$54.3120	$44.4543	$77.4020	$0.00
2022	$55.1081	$44.8772	$77.8248	$0.00
2023	$57.3505	$46.5830	$73.4391	$0.00
2024	$61.3747	$48.3158	$62.4097	$0.00
2025	$64.1766	$50.1315	$66.0836	$0.00
2026	$65.9729	$51.2468	$67.9963	$0.00
2027	$65.8405	$51.1895	$76.5673	$0.00
2028	$67.0843	$52.0674	$82.3914	$0.00
2029	$68.2617	$54.0781	$79.7798	$0.00
2030	$69.5928	$53.9959	$85.0361	$0.00
2031	$71.1634	$55.5444	$90.7860	$0.00
2032	$72.2192	$56.5130	$95.6467	$0.00
2033	$73.4936	$57.8227	$98.8444	$0.00
2034	$75.2577	$58.8672	$104.1880	$0.00
2035	$76.2179	$60.1226	$103.6760	$0.00

APPENDIX F | PHONE SURVEY DATA – OTHER UTILITIES

Table F-1: GDS Phone Survey Data – Other Utilities
Programs That Include DLC of Non-Residential Air Conditioning

Utility	End -Uses	Program Active Since	Incentive	Participation Rate	Equipment Cost	Central Control Equipment Cost	Average kW per Participant Reduction	Total Annual Control Hours	Event Duration (Hours)
Southern CA Edison	AC and Lighting	2009	Not Provided	25%	Not provided	Not Known	Not Known	300	4
Public Service of New Mexico	AC- small commercial	2008	Not Known	Not Known	Not Known	Outsourced	1kW	60	4
Public Service of New Mexico	All End Uses - medium and large commercial	2008	Not Known	2%	Not Known	Outsourced	50kW - 3-4 MW	60	4
PG&E	AC	2010 (program closed in 2011)	$50 - Tstat $25 - Switch (both one time)	<1%	Proprietary	Absorbed by Residential Program	Not Known	Emergency Dispatch Only	Emergency Dispatch Only
PECO	AC	2011	$20/mo. per device	15%	$300 per installed switch or tstat	Not Known	Not Known	Not Known	42,533
Otter Tail Power Co (ND)	AC	2013	$5/AC ton	0.01	Not Known	Not Known	Not Known	300	As required
Great River Energy	All End Uses - Must have behind the meter generation	2000	Varies by Coop	60% - 70%	Not known - Customer must purchase the switch	Not Known	Not Known	400 is allowed: Typical is 20-80	Up to 12
Excel Energy (MN)	AC/some DHW	2000	$5/AC ton	Not Known	$250/ switch	Not Known	Not Known	300	4

MPSC Case No.: U-18419
Respondent: K. L. Bilyeu
Requestor: ELPC
Question No.: ELPCDE-11.13
Page: 1 of 1

Question: Why were incentives limited to 50% of the incremental measure cost in the 2016 DTE Electric Energy Efficiency Potential Study? Has DTE or GDS quantified the impact of limiting incentives to 50% of the incremental measure costs in the 2016 DTE Electric Energy Efficiency Potential Study? Does DTE stipulate that exceeding 50% of the incremental measure cost, even if the additional spending would provide incremental cost-effective benefits, is inappropriate?

Answer: Please refer to page 45 of Exhibit A-32 for a discussion of several reasons why an incentive level of 50% of measure costs was assumed. The 50% of measure cost incentive level is identical to the assumption used in the 2013 Michigan Statewide Energy Efficiency Potential Study published by the Michigan Public Service Commission.

In August 2017, GDS combined the 2016 Energy Efficiency Potential Study results from DTE Energy and Consumers Energy into one study representing the Lower Peninsula of Michigan (please refer to the following link:http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_ Potential_Study_Final_Report_08.11.17_598053_7.pdf). In the combined potential study, GDS performed a 100% incremental cost incentive scenario at the request of the Michigan Public Service Commission. For this scenario, GDS revised the achievable potential for the Consumers Energy and DTE Energy service areas using the assumption that the programs pay 100% of incremental costs for all measures/bundles of measures that would still pass the Utility Cost Test (UCT) at the higher incentive level. Measures that failed the UCT at the 100% of incremental cost were retained at the 50% of incremental cost level. As with the base case achievable potential, all low-income measures with a UCT ratio greater than or equal to 0.5 were retained in this scenario

The Company did not stipulate a 50% incremental measure in the GDS Potential study. As discussed on page 45 of Exhibit A-32, GDS used an incentive level of 50% of measure costs in the potential study because it is a reasonable target based on the current financial incentive levels used by the Company for program participants in existing energy efficiency programs. In some instances, such as for low income measures, it is appropriate to pay an incentive greater than 50% of measure incremental cost.

MPSC Case No.: U-18419
Respondent: D. D. Kirchner
Requestor: ELPC
Question No.: ELPCDE-11.9
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Question: Why does the GDS Demand Response Potential Study assume it will take 20 years to ramp up to the peak participation rates in certain programs when leading utilities have attained higher participation rates in much less time? For example, Baltimore Gas and Electric's Smart Energy Rewards peak time rebate program attained an average participation of 71% in its fourth year (see page 47 of BGE's Q3/Q4 2016 EmPOWER Maryland Portfolio Reporting available at http://webapp.psc.state.md.us/newIntranet/casenum/NewIndex3_VOpenFile.cfm?ServerFilePath=C:\Casenum\9100-9199\9154\\792.pdf) while BGE's PeakRewards direct load control by controllable thermostat program has attained penetration of 33% of eligible homes in eight years (see page 43 of the above referenced report).

Answer: Per GDS Associates, while other utilities may have a fast ramp up speed due to a variety of reasons, the potential study chose a more conservative, 20-year approach. Additionally, DTE already has several DR programs in existence. Fast ramp up speeds usually come with brand new programs, where easy-to-get customers are readily willing to opt in to the program.

In reference to the BGE program, there are significant differences between BGE and DTE in terms of the regulatory landscape. On BGE's Commission approved Smart Energy Rewards® (SER) peak time rebate program, upon getting an AMI meter, all residential customers were enrolled in SER. It is not an opt-in program and the only portion of the program from which customers can opt-out is program communications. The percent participation reflects those who received a bill credit ($1.25/kWh) from an event i.e. those whose load was lower than their individual baseline.

Additionally, on the BGE demand response program: PeakRewards℠, the 33% participation represents the percent participation of eligible customers i.e. residential customers with central A/C, rather than all residential customers. According to testimony from PJM representatives, this program was developed at a time when there was significant concern about meeting electric demand by PJM. Thus, the PSC approved a very aggressive, costly program with regulatory cost recovery treatment. Additionally, the approximate 330,000 participants include many of the prior BGE direct load control program (Rider 5) participants that had been operating for over 15 years. The prior DLC program was a switch program and customers did not have to pro-actively agree to be upgraded to the new PeakRewards program.

MPSC Case No.: U-18419
Respondent: K. L. Bilyeu
Requestor: ELPC
Question No.: ELPCDE-11.12
Page: 1 of 1

Question: In the 2016 DTE Electric Energy Efficiency Potential Study (Witness Bilyeu Exhibit A-32 p 81), the economic potential of commercial Central Lighting Controls, Switching controls for multilevel lighting (Non-HID), Daylight sensor controls, and Occupancy Sensors is a combined 1,109,716 MWh, while the achievable potential of these program is only 55,689 MWh, or only 5.0%. These sensor programs have the one of the largest drops between economic and achievable, and also represent 13.4% of the entire commercial economic potential. Why is the achievable potential so much lower than the economic potential for this program when compared to others? Did DTE discuss potential ways to improve this program to capture a larger portion of the sizable economic savings?

Answer: The identified gap between the commercial economic and achievable potential for the lighting control measures referenced above is the result of a formula error by GDS related to the determination of achievable potential. Per GDS, the formula was improperly calculating achievable potential when the remaining factor for these measures was less than the maximum market penetration. The formula error was noted by GDS in August 2017 when they combined the 2016 Energy Efficiency Potential Study results from DTE Energy and Consumers Energy into one study representing the Lower Peninsula of Michigan as requested by the MPSC.

The table below shows the achievable potential for the lighting control measures referenced above with the corrected formula change per GDS.

Program improvement discussions were outside the scope of the potential study.

Measure	Achievable UCT (MWh)
Central Lighting Control	307,122
Switching Controls for Multilevel Lighting (Non-HID)	169,496
Daylight Sensor Controls	165,983
Occupancy Sensors	78,147

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-4.11a
Page: 1 of 1

Question: Please refer to DTE response MECNRDCSCDE-1.7b and attachment "U-18419- MECNRDCSCDE-1.7 Energy Efficiency Savings.xlsx"

a. How it is possible that the 2% EE savings scenario results in the highest load forecast from 2035-2040 of the EE scenarios contained in columns M to P?

Answer: The Energy Efficiency savings are front loaded in the 2% case compared to the 1%, 1.15% and 1.5% cases, which all use the same potential. As a result, after the 15 year assumed measure lives are completed, this early energy efficiency (2018 to 2021) rolls off because all four programs are assumed to stop in 2030.

MPSC Case No.: U-18419
Respondent: K. J. Chreston/K. L. Bilyeu
Requestor: ELPC
Question No.: ELPCDE-4.10c
Page: 1 of 1

Question: DTE response MECNRDCSCDE-1.6ciii states that "no spend and no incremental energy efficiency [was] added after 2030 in all sensitivities" in order "to fully measure the impact of measures implemented before 2030."

c. If not, why was it important to fully measure the impact of programs implemented before 2030?

Answer: When evaluating long-term programs, it is important to value the effects that occur after the initial outlay of spending. In 2030, the potential was used up from the Potential Study in the 2%, 1.5%, and 1.15% cases, however, the potential was diminished at a different rate for each case. Evaluating all cases on a consistent timeframe is important to understanding the time value of when the potential is diminished as well as the prolonged benefits that occur when there is no additional spend. This method puts the front-loaded programs on an equal basis with the middle and back loaded programs in terms of value.

MPSC Case No.: U-18419
Respondent: K. L. Bilyeu
Requestor: ELPC
Question No.: ELPCDE-4.17d
Page: 1 of 1

Question: Please refer to DTE responses MECNRDCSCDE-1.22d and Witness Bilyeu testimony at page 20.

Refer to the sentence "[o]nce the 'pool' of achievable energy savings potential is saturated, DTE Electric may achieve energy savings at a rate equal to the energy savings as new savings potential emerges due to aging equipment, measure turnover, housing stock development, and technology evolution."

d. If the energy savings potential "pool" from the GDS study is completely captured prior to the end of the study period by accelerating the deployment of energy efficiency measures (e.g. if the 2035 potential savings MWh are attained by 2027), does DTE believe that any additional energy savings is possible through the end of the study period (e.g. between 2028 and 2035 in the above example)?

Answer: The annual incremental increase of energy savings potential is not brought forward and is not achievable until the year it becomes available as identified in the energy efficiency potential study.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-4.1
Page: 1 of 1

Question: In Witness Chreston Exhibit A-10, why does the Required Reserve Margin increase from 7.3% in 2020 to 7.8% in 2028? What is the source for this value for each year in the schedule? What caused the reduction from 7.8% in 2017 to 7.3% in 2019?

Answer: The Required Reserve Margins used in Exhibit A-10 2nd Revised were obtained from MISO's 2017 LOLE Study Report. The report included the MISO System Planning Reserve Margins from 2017-2026. After 2026, the Company carried out the 2026 value of 7.8% for the remaining years of the study period. Please refer to the 2017 LOLE Study Report regarding differences in the Required Reserve Margin.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-4.11c
Page: 1 of 1

Question: Please refer to DTE response MECNRDCSCDE-1.7b and attachment "U-18419-MECNRDCSCDE-1.7 Energy Efficiency Savings.xlsx"

c. Please explain why the Annual NSO with No EE forecast in column K increases steadily until 2030, and then falls until 2040. What demographics or economic trends can possibly explain that forecast?

Answer: The data labeled "Annual NSO with No EE" in column L, were shown as steps in the calculation for creating the response to the discovery question MECNRDCSCDE-1.7 and represent the steps taken to develop the 4 EE levels modeled in the IRP sensitivities. These "No EE" values were not used explicitly in the IRP modeling, (e.g. no zero EE sensitivity was modeled). Therefore, since the data in column L were created as an arithmatical exercise, no trends exist to explain it.

MPSC Case No.: U-18419
Respondent: K. L. Bilyeu
Requestor: ELPC
Question No.: ELPCDE-4.14
Page: 1 of 1

Question: Please refer to DTE response MECNRDCSCDE-1.19civ. If modeled rebate levels are the same between the 1.5% and 2.0% energy efficiency scenarios, what explains the higher and faster adoption of savings measures of the 2.0% scenario when compared to the 1.5% scenario?

Answer: Although the rebate levels are the same, the overall annual cost to achieve 2% is higher. The 2.0% scenario achieves energy savings at a faster rate than the 1.5% scenario and therefore saturates the available achievable potential at a faster rate.

MPSC Case No.: U-18419
Respondent: K. J. Chreston/K. L. Bilyeu
Requestor: ELPC
Question No.: ELPCDE-4.9
Page: 1 of 1

Question: DTE response MECNRDCSCDE-1.3bi references two files that contain the NPV of benefits, costs, and net benefits of the 1.5% EE scenario and the 2.0% EE scenario. In those spreadsheets, the NPV of net benefits (that is, cell B22 – cell B27) of the 1.5% EE scenario is $4.061 billion and the NPV of net benefits of the 2.0% EE scenario is $4.193 billion. In other words, the NPV of the net benefits of the 2.0% scenario exceeds that of the 1.5% scenario by $131.4 million.

Why did DTE choose to forgo an additional $131.4 million in utility cost savings by failing to choose the 2.0% EE scenario?

Answer: DTE selected the 1.5% scenario in part because it has the highest Utility Resource Systems Cost Test (URSCT) score. The URSCT is the investment ratio comparing NPV avoided costs to NPV costs of implementing the program. The greater the ratio, the greater the benefits received for every dollar spent on the program. The USRCT is a measurement of energy efficiency program cost effectiveness from the utility perspective, and is the primary measure used in Michigan to determine the cost effectiveness of an energy efficiency provider program. Thus, in Michigan, USRCT data is available for all energy efficiency plans for all utilities and provides insights and comparisons to cost effectiveness of different programs approaches.

MPSC Case No.: U-18419
Respondent: K. L. Bilyeu/I. M. Dimitry
Requestor: MECNRDCSC
Question No.: MECNRDCSCDE-1.3a
Page: 1 of 1

Question: On p. 23, lines 6-8 of her testimony, Ms. Dimitry states that the 1.5% annual energy efficiency savings level had "the greatest demand reduction while simultaneously being administered within a budget that is consistent with previous levels and it achieves the highest benefit to cost ratio."

a. Why is being able to be "administered within a budget that is consistent with previous levels" relevant in the context of an IRP? If the budget for more savings needed to be higher, but was still lower cost than the alternative of building a new power plant (i.e. instead of no power plant or a smaller power plant), wouldn't that be preferable? If not, why not?

Answer: Although the 1.5% annual energy efficiency savings level included a budget consistent with previous levels, there was not a budget constraint.

A consistent budget supports multi-year planning and budgeting for the Company and its vendors and stability for the Company and vendors in managing work volume and associated staffing. The planned 1.5% level of energy efficiency supports steady progress over many years rather than quickly ramping up and then scaling back significantly when the energy savings potential is saturated (as occurs with the 2.0% level). Stability in offerings to customers and trade allies from year to year can have a significant impact on satisfaction and participation.

In addition, sensitivities with energy savings greater than 1.00% capture an equivalent amount energy efficiency potential by 2030, though the energy savings potential is diminished at different rates. Witness Chreston states in his testimony that the 2.0% energy efficiency sensitivity would defer the first CCGT build by only one year more than the 1.5% energy efficiency sensitivity and does not eliminate the need or reduce the size of the first CCGT build. However, the 2.0% level adds much more volatility to programs.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-8.4b
Page: 1 of 1

Question: Please refer to Exhibit A4- 2nd Revised at page 214.

In the table, DTE compares a 1,100 MW CC plant against three alternatives, each of which has 950 MW of CT along with either solar, wind, or demand response assets. DTE indicates "To make the resource plans equivalent on a capacity basis, a block of CT units is required to firm up the non-dispatchable resources." The Solar portfolio has 500 MW of solar along with 950 MW of CT resources. This implies a solar capacity credit of 30% to create a portfolio with 1,100 MW of resources. However, throughout its analysis, DTE uses a 50% solar capacity credit, which matches MISO's default assumption.

b) What is the source for the 30% capacity credit?

Answer: 41% capacity credit was used. It was based on actual solar performance of the DTE solar fleet from 2016, which was 39% firm. Please see U-18419 ELPCDE-8.4b Wind_Solar ELCC.xls

MPSC Case No.: U-18419
Respondent: D. D. Kirchner
Requestor: ELPC
Question No.: ELPCDE-5.14
Page: 1 of 1

Question: What factors caused DTE to reduce the forecasted subscriptions to the D8 Interruptible Supply Rate program by approximately 100 MW in the 2017 Reference Scenario update? Were any programmatic solutions considered to reverse this reduction? If so, please provide details of the proposed solutions. If not, please explain why actions were not proposed to reverse the reduction.

Answer: The forecasted subscriptions to D8 in the 2016 Reference Scenario were based on the Company's assumptions that expanding the available capacity on the D8 rate from 150 MW to 300 MW in U-17767 would create an increase in the enrolled capacity by commercial and industrial customers who had previously expressed interest in the availability of the rate. The lower enrolled capacity on the D8 rate provided in the update in the 2017 Reference Scenario is based on actual enrollment through 2016. The forecasted customer enrollment on the rate never occurred.

No programmatic solutions were considered to reverse this reduction. Any programmatic solutions required to address D8 would have to be included in a main electric rate case filing.

MPSC Case No.: U-18419
Respondent: I. M. Dimitry
Requestor: ELPC
Question No.: ELPCDE-1.34
Page: 1 of 1

Question: Does DTE believe that it would be feasible for the Company to implement the High Renewables scenario discussed on page TLS-9 of Ms. Schroeder's testimony?

Answer: The High Renewables sensitivity considered an additional 400MW of wind and 1,100MW of solar builds through 2030 compared to the level of renewables assumed in the Reference Scenario (see workpaper KJC-100). The High Renewables sensitivity was run within the Reference, High Gas, and Emerging Technology Scenarios. IRP modeling results considering the High Renewables sensitivity still show the need for a 2x1 CCGT in 2022 to meet the Company's forecasted capacity shortfall.

The cadence and level of solar and wind build in the High Renewables sensitivity is a broad assumption developed to provide insight to the IRP process when evaluating an array of possible futures. While feasible in terms of a modeling exercise, a substantive assessment of the High Renewables sensitivity would require evaluation of customer cost impacts, project siting constraints and grid integration impacts.

MPSC Case No.: U-18419
Respondent: I. M. Dimitry
Requestor: ELPC
Question No.: ELPCDE-4.4
Page: 1 of 2

Question: DTE response ELPCDE-1.34 indicates that the High Renewables scenario would require an additional 400 MW of wind and 1,100 MW of solar through 2030 compared to the Reference Scenario. DTE indicated that the High Renewables scenario is "feasible in terms of a modeling exercise, [but] a substantive assessment of the High Renewables sensitivity would require evaluation of customer cost impacts, project siting constraints and grid impacts." However, the 75% CO2 Reduction by 2040 would require an additional 500 MW of wind and 2,625 MW of solar over the 2017 Reference case as seen on page 225-226 of Chreston Exhibit A-4.

Given DTE's hedging on the feasibility of attaining the High Renewable scenario, what factors make it more confident to attain the 75% CO2 Reduction by 2040 scenario that is consistent with the DTE's recently announced CO2 reduction goals and with DTE Chairman and CEO Gerry Anderson's quote "We have concluded that not only is the 80 percent reduction goal achievable – it is achievable in a way that keeps Michigan's power affordable and reliable. There doesn't have to be a choice between the health of our environment or the health of our economy; we can achieve both."? (Quote available at http://newsroom.dteenergy.com/2017-05-16-DTE-Energy-announces-plan-to-reduce-carbon-emissions-by-80-percent.)

Answer: In the Company's IRP, a High Renewables sensitivity was compared to the Reference Scenario (See workpaper KJC-100), as well as the High Gas scenario, and the Emerging Technology scenario. ELPCDE-1.34 questioned whether the Company felt the High Renewables Sensitivity could feasibly be implemented, and my answer described additional steps that would be needed to assess implementation feasibility of that particular sensitivity.

Such an answer is not inconsistent with the Company's announced goal to reduce carbon emissions by 80% by 2050, or the Gerry Anderson quote mentioned above in this question.

A feasibility assessment is generally associated with a particular project, while the modeling analyses referenced in our IRP were done to demonstrate the Company's forecasted capacity shortfall and select the most prudent and reasonable resource plan to fill the shortfall.

MPSC Case No.: U-18419
Respondent: I. M. Dimitry
Requestor: ELPC
Question No.: ELPCDE-4.4
Page: 2 of 2

The Company believes that there are multiple possible paths – that are both achievable and affordable – that could lead to an 80% reduction in carbon emissions. While we have laid out a possible path in the 75% CO2 Reduction sensitivity seen on page 225 – 226 of Chreston Exhibit A-4 2nd Revised, we have not concluded that this particular renewables resource plan is the most optimal path – just that it is consistent and supportive of our goals within this CON case. The actual renewables plan that will be implemented will surely evolve between now and 2050, and be informed by future IRP analyses and filings, plus feasibility studies of particular renewable projects as they are developed.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-9.5i
Page: 1 of 1

Question: Please refer to WP KJC-375 and KJC-346.

i) Why does DTE assume that capacity prices will remain at CONE from 2022 through 2040 in the no build scenario?

Answer: As described in Section III: Resource Options of my testimony, the “no build” option for such a large amount of long-term capacity need was not considered feasible or prudent. However, since The Filing Requirements and Instructions for Certificate of Public Convenience and Necessity Application Instructions established in the May 11, 2017 order issued in MPSC Case No. U-15896 require “15. Descriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility or significant investment in an existing facility, that were considered, including a **“no-build” option**, and the justification for the choice of the proposed project.”, a no-build option was considered in my testimony.

Since such a large amount of capacity purchases would be required throughout the “No Build” planning period to meet the DTE LCR/PRMR requirements, it is reasonable to assume that a capacity price of CONE which is representative of the MISO Capacity Deficiency Charge or the equivalent cost of someone building a large amount of capacity for DTE’s benefit.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-9.5b
Page: 1 of 1

Question: Please refer to WP KJC-375 and KJC-346.

b) What are the primary differences in the assumptions between these two capacity price schedules?

Answer: The 2017 PACE Reference capacity price forecast is based on PACE's fundamental modeling. The CONE 2022 capacity price forecast is the same as the 2017 PACE Reference up to 2021. In 2022, the forecast goes to CONE and is adjusted for inflation with the DTE Deflator series. Please refer to ELPCDE-9.5a for the assumptions of both forecasts.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-9.5d
Page: 1 of 1

Question: Please refer to WP KJC-375 and KJC-346.

d) Is the CONE used in KJC-346 representative of Net CONE or Gross CONE?

Answer: Gross CONE.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-9.5f
Page: 1 of 1

Question: Please refer to WP KJC-375 and KJC-346.

f) The CONE 2022 capacity prices appear to inflate the 2022 CONE of $94.90/kW by the deflator used in this model for the years 2022 through 2040. Please confirm if this is what the model is doing. If the values for 2022 through 2040 are calculated through another method, please indicate what that is.

Answer: Confirmed.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-9.5e
Page: 1 of 1

Question: Please refer to WP KJC-375 and KJC-346.

e) If the answer to part "d)" above is not Net CONE, why did DTE not use Net CONE for this capacity price projection?

Answer: The large capacity purchase requirements in the "No Build" sensitivity was forecasted to trigger the MISO Capacity Deficiency Charge which is based on Gross CONE.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-9.5j
Page: 1 of 1

Question: Please refer to WP KJC-375 and KJC-346.

j) Does DTE believe that the MISO capacity market construct will fail to incent new entry of either generation assets, storage assets, or transmission assets when prices remain at CONE for 19 consecutive years?

Answer: No. See ELPCDE -9.5i.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-3.8
Page: 1 of 1

Question: Please provide a version of Exhibit A-9 (all pages), the Proposed Project Revenue Requirement (based on 2017 Reference) from 2016-2040, without also including the second combined-cycle gas plant that DTE would like to build in 2029. In other words, please provide the annual Project Revenue Requirement only for the 1,100 MW gas plant that DTE proposes to bring on-line in 2023 and for which DTE requests a CON in this case.

Page 5 of 5 of the current Exhibit A-9 appears to show the annual revenue requirements for both the 2023 and 2029 combined-cycle plants; Vote Solar would like to see just the annual revenue requirements from 2016-2040 for the 2023 combined cycle that is the subject of this case.

Please also show the net PSCR impacts just for the 2023 plant.

Answer: A version of Exhibit A-9 without the second combined cycle in 2029 does not exist.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-10.1
Page: 1 of 1

Question: Refer to WP KJC-344 and KJC-345.

What is the carbon intensity by year in tons/MWh that is assumed for market purchases, for the Proposed Project, and for the NGCC constructed in 2029 in both the Proposed Plan (KJC-344) and No Build (KJC-345) scenarios?

Answer: Please see U-18419 ELPCDE-10.1 Carbon Intensity.xls for the carbon intensity of the Proposed project and the 2029 CCGT.

The Company did not assume a carbon intensity value for purchases or sales.

MPSC Case No.: U-18419
Respondent: W. H. Damon
Requestor: ELPC
Question No.: ELPCDE-3.13d
Page: 1 of 1

Question: Please provide the following data for DTE's proposed gas-fired combined-cycle plant:

d. Expected time to reach full output from (1) a cold start and (2) minimum load at the expected Minimum Emission Compliance Limit (MECL).

Answer: At ISO conditions (59F 60% RH), the plant is expected to reach full unfired output in approximately 200 minutes under a cold start condition. This time will vary depending on ambient conditions. At ISO conditions and as part of cold start, the plant will be capable of ramping from MECL to full load in approximately 170 minutes.

MPSC Case No.:	U-18419
Respondent:	K. J. Chreston
Requestor:	ELPC
Question No.:	ELPCDE-3.13e
Page:	1 of 1

Question: Please provide the following data for DTE's proposed gas-fired combined-cycle plant:

e. Expected minimum run time for the plant, in hours, under normal operations.

Answer: The expected minimum runtime is 4 hours as modeled in the IRP.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-3.13f
Page: 1 of 1

Question: Please provide the following data for DTE's proposed gas-fired combined-cycle plant:

f. The anticipated number of scheduled maintenance hours each year.

Answer: A levelized scheduled maintenance rate of 2% was modeled in every year. Please refer to the table below for the equivalent maintenance hours

Proposed Gas-Fired Combined-Cycle Plant Modeled Scheduled Maintenance Hours	
Year	Scheduled Maintenance Hours
2022	102
2023	175
2024	175
2025	175
2026	175
2027	175
2028	175
2029	175
2030	175
2031	175
2032	175
2033	174
2034	176
2035	175
2036	175
2037	175
2038	176
2039	175
2040	175

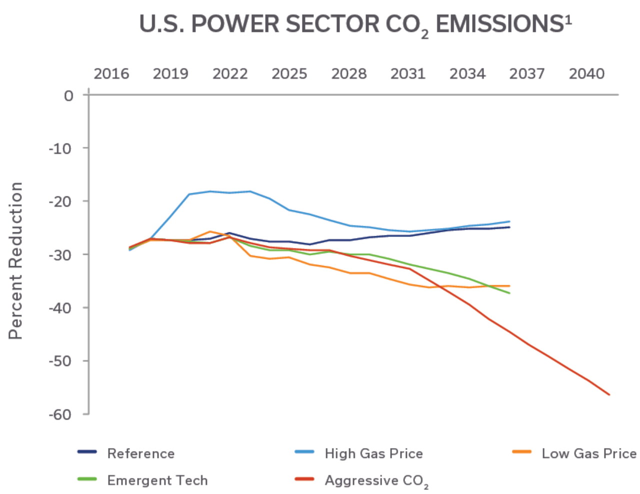
MPSC Case No.: U-18419
Respondent: K. J. Chreston /B. J. Marietta
Requestor: ELPC
Question No.: ELPCDE-3.2e
Page: 1 of 2

Question: Refer to Exhibit A-4, the 2017 Integrated Resource Plan.

e. With regards to the Aggressive CO2 scenario, please provide the annual carbon reduction requirements that were applied to the generation fleet.

Answer: Nationally, the carbon reduction requirements listed below were applied in the PACE national modeling as shown in the Exhibit A-4, Figure 11.2.4-2:

Figure 11.2.4-2



[1]The Aggressive CO_2 scenario was modeled in the National models out to 2040 due to its more significant changes in the years 2035 to 2040. The changes in the other cases in the years 2035 to 2040 were less significant, so they were modeled only in the National model through 2035.

For the DTE fleet, the following reduction was assumed. The years 2041 to 2050 were not modeled in the IRP modeling. They are shown to illustrate meeting 80% reduction by 2050 on a straight line from 2030:

MPSC Case No.: U-18419
Respondent: K. J. Chreston /B. J. Marietta
Requestor: ELPC
Question No.: ELPCDE-3.2e
Page: 2 of 2

	% Carbon reduction from 2005 level in the Aggressive CO2 Scenario
2022	32%
2023	32%
2024	32%
2025	41%
2026	41%
2027	41%
2028	44%
2029	44%
2030	46%
2031	48%
2032	49%
2033	51%
2034	53%
2035	54%
2036	56%
2037	58%
2038	59%
2039	61%
2040	63%
2041	65%
2042	66%
2043	68%
2044	70%
2045	71%
2046	73%
2047	75%
2048	77%
2049	78%
2050	80%

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: MECNRDCSC
Question No.: MECNRDCSCDE-5.7a
Page: 1 of 1

Question: PACE model: Refer to KJC-374, tab “New Builds Summary.”

a. Provide a toplogy, map, or key for the zones shown here.

Answer: Please see MECNRDCSCDE-5.7a.pdf

MECNRDCSCDE-5.7a

Figure 1: Map of Aurora Zones

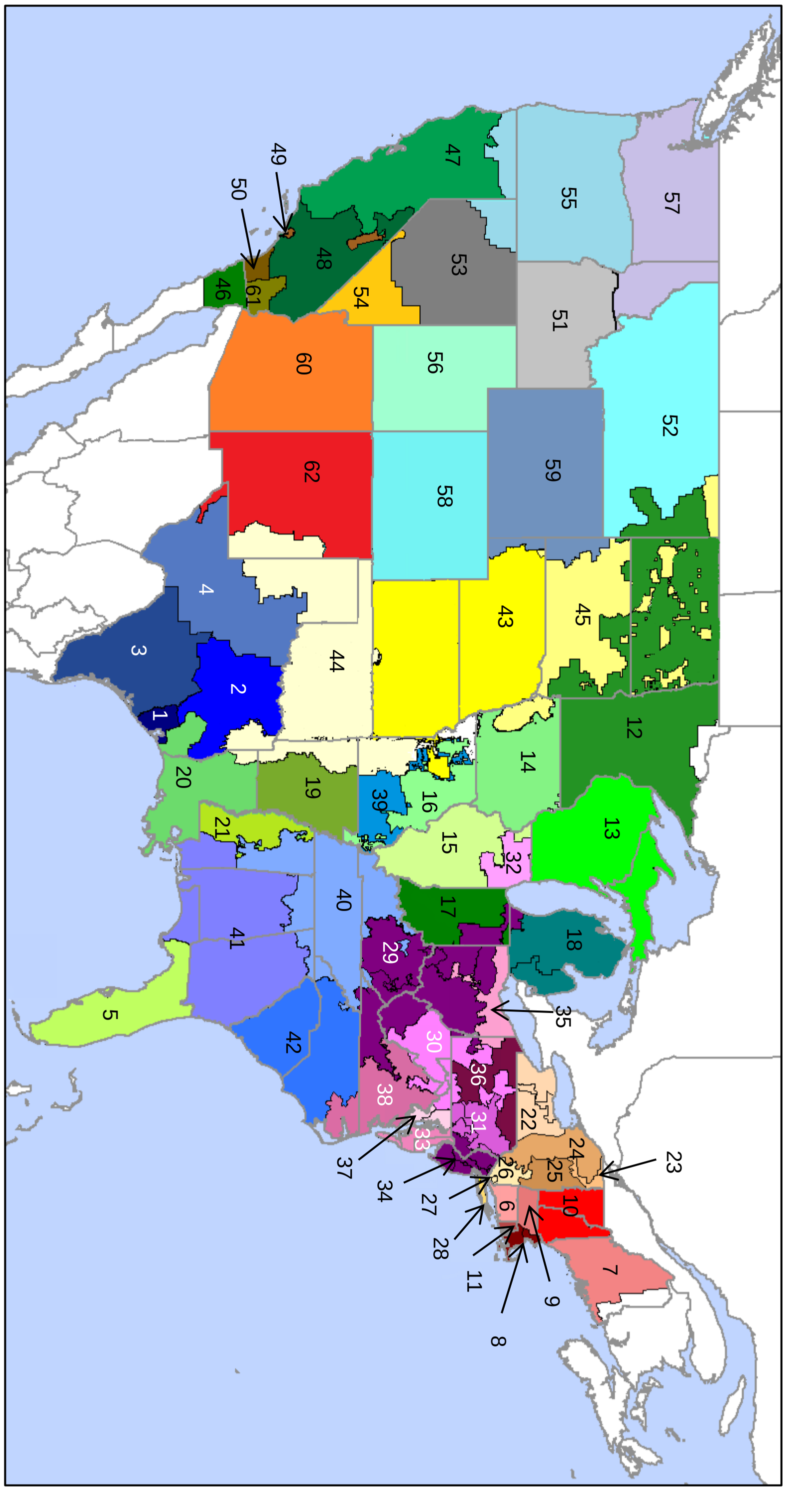


Table 1: List of Aurora Zones

Zone ID	Zone Name	Short Zone Name	Pool ID
1	ERCOT Houston	ERCOT-H	ERCOT
2	ERCOT North	ERCOT-N	ERCOT
3	ERCOT South	ERCOT-S	ERCOT
4	ERCOT West	ERCOT-W	ERCOT
5	US-EI-FRCC	FRCC	FRCC
6	US-EI-Isone-Connecticut	CTRI	ISONE
7	US-EI-Isone-Maine	BHE	ISONE
8	US-EI-Isone-Mass Boston	MassBoston	ISONE
9	US-EI-Isone-MassHub	MassHub	ISONE
10	US-EI-Isone-NewHampshireVermont	NHVT	ISONE
11	US-EI-Isone-RhodeIsland	RI	ISONE
12	US-EI-MISO-LZ1-MRO	MRO-MISO	MISO
13	US-EI-MISO-LZ2-WUMS	WUMS	MISO
14	US-EI-MISO-LZ3-AlliantWest	AltW	MISO
15	US-EI-MISO-LZ4-GatewayIL	Gateway-IL	MISO
16	US-EI-MISO-LZ5-GatewayMO	Gateway-MO	MISO
17	US-EI-MISO-LZ6-Indiana	CIN	MISO
18	US-EI-MISO-LZ7-MECS	MECS	MISO
19	US-EI-MISO-LZ8-Arkansas	Delta-AR	MISO
20	US-EI-MISO-LZ9-GulfStates	Delta-Gulf	MISO
21	US-EI-MISO-LZ10-Mississippi	Delta-MS	MISO
22	US-EI-NYiso-A-C	NYA-C	NYISO
23	US-EI-NYiso-D	NYD	NYISO
24	US-EI-NYiso-E	NYE	NYISO
25	US-EI-NYiso-F	NYF	NYISO
26	US-EI-NYiso-GHI	NYGHI	NYISO
27	US-EI-NYiso-J-NYC	NYJ	NYISO
28	US-EI-NYiso-K-LongIsland	NYK	NYISO
29	US-EI-PJM-AEP	PJM_AEP	PJM
30	US-EI-PJM-Allegheny Power	PJM_W	PJM
31	US-EI-PJM-Central	PJM_C	PJM
32	US-EI-PJM-COMED(NI)	ComEd	PJM
33	US-EI-PJM-DelMarva	PJM_Del	PJM
34	US-EI-PJM-East	PJM_E	PJM
35	US-EI-PJM-First Energy	PJM_FE	PJM
36	US-EI-PJM-Penelec	PJM_W	PJM
37	US-EI-PJM-South	PJM_S	PJM
38	US-EI-PJM-VACAR-Dominion	PJM_VACAR	PJM
39	US-EI-SERC_AssociatedElectric	AECI	SERC
40	US-EI-SERC-Central	SERC-C	SERC
41	US-EI-SERC-Southeastern	SERC-S	SERC
42	US-EI-SERC-VACARSouth	VACARSo	SERC
43	US-EI-SPP-North	SPP-N	SPP
44	US-EI-SPP-South	SPP-S	SPP
45	US-EI-SPP-WAUE	SPP-WAUE	SPP
46	Mexico-WECC-BajaCa-BajaCa	BajaN	WECC_CAMX
47	US-WECC-CAISO-CaliforniaNorth	CA-N	WECC_CAMX
48	US-WECC-CAISO-CaliforniaSouth	CA-S	WECC_CAMX
49	US-WECC-CAISO-SanDeigo	CA-SD	WECC_CAMX
50	US-WECC-LADWP	LADWP	WECC_CAMX
51	US-WECC-IdahoSouth	ID-So	WECC_NWPP
52	US-WECC-Montana	MT	WECC_NWPP
53	US-WECC-NevadaNorth	NVNo	WECC_NWPP
54	US-WECC-NevadaSouth	NVSo	WECC_NWPP
55	US-WECC-Oregon	OR	WECC_NWPP
56	US-WECC-Utah	UT	WECC_NWPP
57	US-WECC-WashingtonIdaho	OWI	WECC_NWPP
58	US-WECC-Colorado	CO	WECC_RMRG
59	US-WECC-Wyoming	WY	WECC_RMRG
60	US-WECC-Arizona	AZ	WECC_SRSG
61	US-WECC-ImperialIrrigation	IIP	WECC_SRSG
62	US-WECC-NewMexico	NM	WECC_SRSG

MPSC Case No.: U-18419
Respondent: B. J. Marietta/K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-5.25
Page: 1 of 1

Question: After the last coal plant is retired in 2040, what are DTE's plans to attain deeper reductions to hit their 2050 GHG emission reduction goals?

Answer: Current plans include further curtailment of the remaining fossil fleet through retirements or lower capacity factors on gas and oil-fired units, continuing to add renewable generation, looking for emerging technologies that support lower emissions, and looking for further energy waste reduction opportunities.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: STAFF
Question No.: STDE-2.6b
Page: 1 of 1

Question: With regard to the Company's Volt/VAR pilot mentioned in witness Chreston's testimony:

b. How many circuits does the Company intend to install Volt/VAR capability on?

Answer: The pilot planned for 2018 is to study upgrades to regulators and capacitors with remote capabilities. It is not a Volt/VAR pilot, therefore, the number of circuits on which the Company intends to install Volt/VAR capability are not known at this time.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-5.7
Page: 1 of 2

Question: Please provide the experience and qualifications of all subject matter experts that participated in the Analytic Hierarchy Process (AHP) risk analysis, including what scenario they were assigned to. If they were DTE employees, please indicate their title and department.

Answer: The Company used a reviewing panel that produced five sets of ratings that were weighted equally. The panel consisted of four individual SMEs and the fifth set of ratings was produced by a committee comprised of members of the IRP and Modeling group. All scenarios and all attributes were rated by the reviewing panel. All participants were DTE employees. Titles and years of industry experience are listed, years are DTE unless otherwise indicated.

SME 1: IRP and Modeling, which is part of Business Planning and Development dept, participating in AHP as a committee approach:

Supervisor – Professional
IRP & Modeling
22 years

Manager – Strategy & Planning
IRP & Modeling
35 years

Senior Strategist
IRP & Modeling
10 years

Specialist – Market Operations
IRP & Modeling
11 years

Principal Market Engineer
IRP & Modeling
8 years

SME 2: VP Plant Operations – Fossil Generation
Electric Industry 25 years
DTE - 17

MPSC Case No.:	U-18419
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Page:	2 of 2

SME 3: VP Business Planning & Development
23 years

SME 4: VP Environmental Management & Resources
30 years

SME 5: Controller – DTE Electric
27 years - started with DTE Gas (MichCon) in 1990
Electric Controller since 2014.

There were also load sensitivities and a high capital cost sensitivity. These were rated by separate SMEs as follows:

Load Sensitivities:

Manager – Corporate Energy Forecasting
Corporate Energy Forecasting
Electric Industry 11 years
DTE 7 years

High Capital Cost Sensitivity:

Platform Manager
Major Enterprise Projects
24 years

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-5.8
Page: 1 of 1

Question: Did any external party (other than potential outside subject matter experts that worked on the AHP) review the inputs to the AHP risk analysis? If so, please indicate the nature of the party (i.e. hired contractor, stakeholder in public proceeding, etc).

Answer: No.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-5.13
Page: 1 of 1

Question: Please provide the full inputs and results of all 200 draws of the stochastic analysis discussed on page 52 of Mr. Chreston's testimony.

Answer: Please refer to attachment 'STDE-16.1a Stochastic risk draws.xls' from question 'STDE-16.1a' for the inputs.

Please refer to attachment 'U18419-ELPCDE 5.13 Stochastic Analysis 200 Draws Results.xls' for the results.

MPSC Case No.: U-18419
Respondent: A. Holland, K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-6.1a
Page: 1 of 1

Question: Refer to Chreston Workpaper KJC-320.

a. What distribution function did PACE use to calculate the inputs to the Stochastic risk analysis?

Answer: **Load:**

For Load (demand) stochastic variables, Pace Global used a Normal Distribution to factor-in the deviations around the reference forecast. Reference forecast refers to the fundamental projections in the ISO's official reports.

In the first step, Pace Global constructs a multiple regression analysis with respect to weather and economic variables (Personal Income in this case).

To account for "unexplained" variations in the forecast, Pace Global adds a normally distributed residual with mean zero and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

Natural Gas and Coal Prices:

For these two sets of commodity prices, the daily price returns are found to be normally distributed, with a constant "drift" rate and variations to the drift (sigma). Such price behavior is usually modeled using a "Log-Normal" distribution, as it is widely discussed in the literature. Pace Global used "Log-Normal" distribution to model gas and coal price stochastics.

Emissions and Capital Costs:

For emissions prices, there is no historical data to estimate the parameters. The stochastic distributions are based on expert opinion forecasts of base, low and high price trajectories. Pace Global used a "Normal distribution" as an underlying, to come up with a set of stochastic distributions that satisfies the expert opinion based high and low forecasts.

For capital costs, the stochastic distributions are based on expert opinion forecasts of base, low and high cost trajectories. Pace Global used a "Normal distribution" as an underlying.

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Question No.: ELPCDE-6.1b
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Question: Refer to Chreston Workpaper KJC-320.

b. Was the same distribution used for each variable?

Answer: No; different distributions were used for the driver variables. Please refer to ELPCDE-6.1a.

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Question No.: ELPCDE-6.1c
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Question: Refer to Chreston Workpaper KJC-320.

c. Please provide all data (such as mean, standard deviation, etc.) needed to reproduce the input values for each variable.

Answer: The mathematical equations used to obtain the stochastic distributions are different for each of the driver variables. It's not as simple as using a single value for mean and standard deviation and running them through an assumed equation. In order to replicate what was done by Pace Global, a set of supporting parameter coefficients also needs to be used.

It is to be noted that Pace Global's stochastic distributions are all generated using a "reference forecast" as the base, for all the forecast years.

For demand stochastics, the "mean" values are the base forecasts for average and peak load, which varies by month-year, throughout the forecast years. To model the unexplained variations, Pace Global used a normal distribution with mean "0" and standard deviation equal to the root mean squared error of the previously mentioned stepwise regression.

For Natural gas and Coal prices, Pace Global used a single-factor mean reverting model to generate the stochastic distributions. The mean values are the base forecasts that are obtained from Pace Global's internal fuels expert group, for each of the forecast month-year. Since the daily price changes have historically exhibited a normal distribution, Pace Global used a standard deviation of "1" to model the randomness in daily price changes.

In addition to these values for mean and standard deviation, other parameters such as "Mean Reversion coefficient", correlation matrices etc. are also required to reproduce the results for gas and coal prices.

For CO2 and capital costs, the mean values are the base price forecasts. The standard deviation values are dependent on the expert opinion based forecast of the high and low cases respectively, which differ for each year.

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Question No.: ELPCDE-6.1e
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Question: Refer to Chreston Workpaper KJC-320.

e. Given that 20 variables are contained in KJC-320 with stochastic inputs, does PACE feel that 200 runs were sufficient to thoroughly explore the distribution of results that might occur?

Answer: The key element in any Monte-Carlo analysis is determining the number of iterations ("simulations") that should be run in order to derive the answer to an objective function.

- Pace Global used the theory of "Statistical Convergence" in estimating the optimal number of simulations required for each of the market driver variables, which include prices and demand elements.

- In addition to this, the driver variables are not Independent Distributions; there is a higher "degree of correlation" observed in the market place among natural gas prices, coal prices and CO2 costs.

Given these facts, Pace Global ended up using 2000 simulations for generating the probability distributions for each of the market driver variables.

Though AuroraXMP is a fundamental model, it is complex and takes significant run-time. This needs high performance computational machines, large output databases, and long run-times. Thus, there is a trade-off between performing the number of simulations and the stability in the Aurora results. Therefore, Pace Global utilizes the process of "Stratified Sampling" to pick 200 iterations from the actual population of 2000 iterations of the market driver variable to provide as inputs to AuroraXMP. This technique makes sure that the distribution tails are captured well.

Pace Global has performed test runs for different power market zonal regions across the U.S. and measured parameters such as market energy prices, margins of assets and the cash-flows generated over the long-term study period etc. These tests indicated that performing 200 simulations is sufficient for tasks such as resource planning studies, financial valuations and structured deals analysis.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

DIRECT TESTIMONY OF

MICHAEL B. JACOBS

ON BEHALF OF

THE ENVIRONMENTAL LAW & POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Michael B. Jacobs. My business address is 2 Brattle Square, Cambridge, Massachusetts.

Q. By whom are you employed and in what capacity?

A. I am employed by the Union of Concerned Scientists ("UCS") as Senior Energy Analyst.

Q. What is the mission of the Union of Concerned Scientists?

A. "The Union of Concerned Scientists puts rigorous, independent science to work to solve our planet's most pressing problems. Joining with citizens across the country, we combine technical analysis and effective advocacy to create innovative, practical solutions for a healthy, safe, and sustainable future." http://www.ucsusa.org/about-us#.VGVEiPnF98E.

Q. Please describe your educational background.

A. I am a graduate of Wesleyan University, Middletown, Connecticut. I received a Master of Science degree from the University of Wisconsin – Madison in the Department of Urban and Regional Planning.

Q. Please describe your professional background.

A. I am an analyst with over twenty-five years of experience in the utility and energy regulatory fields. I am responsible for UCS' efforts to promote the understanding and adoption of clean energy alternatives in the energy markets serving the states and regional transmission organizations where UCS has broader advocacy efforts. I joined the UCS after participating in regulatory and market reforms for the wind industry, an energy storage company, and the National Renewable Energy Laboratory. In these capacities I was responsible for representing my employers in utility regulatory discussions and rulemakings.

I began my career as a member of the staff of the Massachusetts Department of Public Utilities and Energy Facilities Siting Council, where I helped write the rules for, and then mediate a settlement in, the implementation of all-resource competition to fill utility procurement requirements. While I was the Acting Policy Director for the American Wind Energy Association, I participated in a Federal Energy Regulatory Commission ("FERC") settlement of interconnection standards and jurisdiction for small generators with the representatives of the National Association of Regulatory Utility Commissioners. Also at that time, I led the wind industry to a settlement with the North American Electricity Reliability Council (now Corporation) over certain requirements for large generator interconnection.

Q. Have you testified before this Commission as an expert?

A. No.

Q. Have you provided testimony or comment as an expert before any other Commission?

A. Yes. For prior employers, I have submitted written comments in proceedings at FERC on the implementation of wind farm interconnection procedures and provided pre-filed written testimony before the Public Utility Commission of Maine regarding the development of transmission for wind farms and the New Jersey Board of Public Utilities regarding renewable energy policy before and after a proposed merger of utility companies. A list of state and federal proceedings where I have provided comments is attached to my testimony as Exhibit ELP-57 (MBJ-1).

Q. Are you sponsoring any other exhibits?

A. No.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing in this case?

A. I am testifying on behalf of the Environmental Law and Policy Center, Union of Concerned Scientists, Vote Solar, Solar Energy Industries Association, and the Ecology Center.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the manner in which DTE addressed advanced energy storage, in particular battery storage resources, in the Integrated Resource Plan ("IRP") and in its comparison of options for new resources.

Q. Please summarize your testimony.

A. As my testimony will detail, battery storage resources are commercially available, are being cost-effectively developed under a variety of circumstances across the country, and have the potential to provide benefits to DTE's system and ultimately its ratepayers. While DTE summarily recognizes the potential benefits of battery storage resources, it does not perform a reasonably adequate analysis of the costs and benefits of including battery storage in its resource portfolio, uses arbitrarily inflated cost assumptions in what limited evaluation it does perform, and generally dismisses battery storage as a resource option without adequate justification. DTE's failure to adequately evaluate how battery storage resources, either separately or in combination with other resource options, can lower the costs of energy and capacity for consumers – particularly in light of its stated commitment to reducing carbon emissions by 80 percent by 2050 – makes it impossible to conclude that DTE's preferred plan is the most reasonable and prudent course of action for meeting the future energy needs of its ratepayers.

III. POTENTIAL BENEFITS OF BATTERY STORAGE RESOURCES

Q. What benefits can battery storage resources provide to DTE's system?

A. Because of their unique attributes, battery storage resources have the potential to provide several different benefits to DTE's electric system, and ultimately to its ratepayers. Initially, battery storage resources can be developed incrementally and very quickly compared to other resources – often within a year. This allows utilities and developers to respond to identified immediate needs rather than planning for projected needs far into the future, thereby significantly reducing the risks typically associated with utility-scale capital investments.

As simply an energy resource, battery storage systems provide flexibility because they can serve as both a sink and a source of energy, thereby creating price arbitrage opportunities – i.e. storing energy when prices are low and delivering low-cost energy when wholesale prices are high. Battery storage resources that are designed for arbitrage can also serve as capacity or demand response resources for meeting peak demand or reliability requirements.

Battery storage resources can also serve as a grid resource to address congestion or other energy flow issues, and thereby increasing the efficiency of the electric delivery system or deferring other potentially costly transmission and distribution system upgrades.

Finally, battery storage resources of varying designs provide a host of benefits commonly referred to as "ancillary services". Primary among the ancillary services provided by commercial battery storage resources is frequency regulation. The value of these services is well established, and the economic impact on a resource plan can be quantified when running properly designed system models that captures intra-hour interactions. More to the point for DTE, as an operator of a Local Balancing Area responsible for providing a larger range of services including grid reliability, providing reserves and improving the efficiency of load-following can reduce the cost of operating the balancing area and meeting customer needs.

Q. What is frequency regulation?

A. Frequency regulation addresses the mismatch between electricity generation and demand that can lead to variations in frequency that impact the electric grid and ultimately the reliable delivery of electricity. Frequency regulation requires some portion of the on-line resources to move up or down to correct imbalances on a shorter time scale than the instructions given through dispatch to the rest of the fleet of resources.

Q. Is the ability of battery storage resources to provide ancillary services recognized in wholesale markets?

A. Yes. Where battery storage resources perform in a manner similar to pumped hydro storage, or conventional generators, wholesale markets are capable of recognizing ancillary services from battery storage resources. In addition, late in 2011 FERC issued Order 755 requiring organized energy markets such as PJM and MISO to change the measurement and compensation for frequency regulation. This decision was important for the recognition of the unique capabilities of battery storage resources to provide ancillary services. Order 755 led to the adoption of compensation in wholesale markets that rewarded the speed and accuracy of the ancillary service of frequency regulation.

Q. Is there a difference in the ability of advanced battery storage to provide ancillary services in comparison with a gas-fired CC or gas-fired CT unit?

A. Yes. There are two important ways that an advanced battery storage resource is different – and in many cases superior – to a gas-fired generator in their respective abilities to provide ancillary services.

First, the range of capacity available for ancillary services in a gas-fired unit is considerably smaller than the range available for ancillary services from an energy storage unit. A gas-fired unit has a minimum operating limit, below which the unit cannot produce energy. In a gas-fired combustion turbine (CT), this operating lower limit is typically 20% of its nameplate capacity. Thus, the range of flexibility for a CT is 80% of its capacity.

A combined cycle unit has a narrower range of flexibility, as such a plant depends on one or more CTs to operate at a higher level in order to generate the heat that is captured for the second cycle to make a steam turbine spin. The limits of the CT and the steam turbine define the range of flexibility for a combined cycle generator.

For a battery-based energy storage resource, the range of flexibility available for providing ancillary services is wider because the unit can operate in both positive and negative directions. Depending on the desired service (such as frequency regulation and response, which may need to be either positive or negative), and whether the unit is absorbing energy at the time, the range of an energy storage resource can be 200% of its nameplate capacity rating.

Second, the ancillary services benefits of energy storage are different from those of gas-fired generation because the number of hours in a year in which the capacity is available for providing services are different. A battery-based energy storage unit does not depend on the dispatch of its energy generation to make its capacity available to provide ancillary services. The availability of battery storage to provide a full range of grid services is not limited to hours when the produced energy is economic, and it does not require the resource to be dispatched out of merit order.

IV. PROJECTED COST DECLINES IN BATTERY STORAGE RESOURCES

Q. What is the projected trend of Energy Storage costs?

A. Energy storage costs are expected to decline significantly over the next five years. In evaluating battery storage as a resource, industry experts and utilities commonly rely on the Lazard annual Levelized Cost of Storage reports that describe projected cost reductions for lithium-ion battery systems in reports released late in 2015, 2016 and 2017. In these reports, the five-year cumulative cost declines identified as the average projection for lithium-ion has been 47%, 38% and 36% respectively. The Lazard analysis includes the cost of balance of system and installation.

Lazard provides overnight capital costs for various scale and types of deployments. In a specific use case of 4-hour duration, the 2017 observed lithium-ion peaker-plant cost is $1,338 per KW and $335 per kwh. This kwh value is 20% lower than the low end of the range from the previous year. In the 2016 Lazard report, 4-hour duration lithium-ion systems were reported in the range $417-949/kwh.

Practitioners in this field also rely on additional projections released in 2016 that are available from commercial sources, namely Bloomberg New Energy Finance, Navigant Consulting, and Greentech Media. These three firms have made 5-year projections of lithium-ion battery systems of 4-hour duration that are within the range of reductions, 35%-45%, that Lazard defined in the series of reports described above.

Other researchers have described past and projected costs for lithium-ion energy storage. A study coordinated by the Joint Institute for Strategic Energy Analysis with NREL and HOMER Energy staff gathered price decline information and projections. This paper reported battery prices fell by 65% from 2010 to 2015, and total capital costs for an 8-hour storage system are projected to decline by 34% to 81%, with the expected size of the decrease at 57% by 2050.

As I discuss further below, utility IRP filings in other states use declining capital costs of about 50 percent over the next five years. Later in my testimony, I discuss DTE's development of planning inputs and modeling of energy storage. In stark contrast to the well-accepted sources I just described, the cost declines used by DTE are only about half (26% over five years) of the declines projected my commonly cited industry projections and those used by other utilities in 2016 and 2017 IRP processes.

V. BATTERY STORAGE RESOURCES IN STATE IRP PROCEEDINGS

Q. Have other state-supervised IRP processes recognized battery storage resources?

A. Yes. State-supervised Integrated Resource Plans conducted by utilities around the country and in adjacent Indiana have included advanced battery storage among the studied, ***and selected*** advanced energy storage resources. Below is a list of utilities that have included advanced battery storage in the selected resource plan, and some description where these utilities made relevant changes to their IRP process to reflect the realities of energy storage as a resource option.

- Indianapolis Power & Light 2016 IRP
- Arizona Public Service 2017 IRP
- Portland General Electric 2016 IRP
- Public Service Co. of New Mexico 2017 IRP
- Tucson Electric Power 2017 IRP

Q. As part of developing your testimony in this case, have you reviewed any IRPs that included energy storage as a resource option?

A. Yes. Both as part of my development of testimony in this case and as part of my normal professional work, I have reviewed the IRPs that I listed above.

Q. Can you briefly explain how those IRPs treated advanced battery storage resources?

A. The 2016 IRP from Indiana Power & Light (IPL)[1] describes its existing battery energy storage system and its capacity credit in MISO. IPL explains the advantages in operational range and availability of battery energy storage in comparison to a gas-fired combustion turbine: "generators can only provide essential reliability services if the generator is dispatched. It (a battery storage system) does not have to already be operating or "spinning"." IPL 2016 IRP Volume 1, p. 88.[2] IPL used declining capital costs over 20 years of approximately 5% to 10% per year. The IRP capacity expansion model was able to select from two different configurations of 50 MW and 20 MW.

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[1] https://www.iplpower.com/Our_Company/Regulatory/Filings/IRP_2016/IPL_2016_IRP_Volume_1_110116-compressed/

[2] Access the IPL report at: https://www.iplpower.com/Our_Company/Regulatory/Filings/IRP_2016/IPL_2016_IRP_Volume_1_110116-compressed/

The results of IPL resource planning in 2016 resulted in the selection of significant additions of battery storage resources. The IPL Base Case resource plan included an increase of 500 MW of battery storage. The Hybrid resource plan, selected by IPL, includes 283 MW additional battery storage.

The 2017 IRP completed by Arizona Public Service (APS)[3] chose a portfolio after screening and evaluation that it described as its Flexible Resource Portfolio. APS recognized energy storage for its risk management benefits, and the potential for APS to use energy storage, and the resource portfolio selected, to adapt in a variety of future market conditions. (See for example pages 119-128.) APS included energy storage in each of the resource portfolios that were then compared using the Strategist model. This led to selection of 503 MW of new storage addition.

The 2016 IRP completed by Portland General Electric (PGE)[4] evaluated storage as part of an increased effort to understand operational needs. PGE simulated the behavior of energy storage in its resource portfolio as part of its IRP. The IRP examines intra-hour value of the addition of energy storage through modeling operations, ancillary services requirements, and sub-hourly dispatch. PGE compared the use of resources for contingency reserves and frequency regulation with and without energy storage included in the resource mix. PGE determined operational value of energy storage by comparing the total annual simulated operating costs of running their fleet to meet demand with and without energy storage for a test year, 2021. (See pp 235-239) PGE also used a Loss-of-

[3] https://www.aps.com/library/resource%20alt/2017IntegratedResourcePlan.pdf
[4] https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016-irp.pdf?la=en

Load-Expectation calculation to evaluate the capacity value of resources, including storage resources. PGE will submit one or more proposals to the Oregon Commission for developing energy storage systems that have the capacity to store at least 5 megawatt-hours of energy in early 2018.

The 2017 IRP completed by Public Service Co. of New Mexico (PNM)[5] used several tools in addition to the Strategist model to compare scenarios and examine the value of energy storage. PNM used AuroraXMP to explore hourly economic dispatch and impact of need for reserves, SERVM for reserve margin and LOLP analysis, and also incorporated analyses performed by Astrapé Consulting to assess the ability of battery storage in helping PNM maintain system reliability. (See, for example, pgs. 120-121)

PNM compared LOLP, curtailment of renewable energy, and total costs for five cases ranging from the base case to a variety of peaking plant or energy storage configurations. (p. 125) The analyses showed that replacement of a coal plant should be a peaking resource with operational flexibility, and that in high renewable scenarios battery storage can be a cost-effective replacement for natural gas capacity. (See, for example, p. 128)

PNM indicated that it will issue a request for proposals for energy storage, renewable energy, and flexible natural gas resources to confirm the assumptions and analysis results in their report and to further refine the mix of coal-plant replacement resources. (See, for example, p. 148)

[5] https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Final.pdf/eae4efd7-3de5-47b4-b686-1ab37641b4ed

Tucson Electric Power (TEP) completed a 2017 IRP[6] with several considerations of the value of battery storage resources for capacity flexibility and reliability. TEP created a Reference Case Plan that directs the implementation of three battery storage systems in coming years. TEP plans to add a battery storage facility in the years 2019, 2021, and 2031. The systems in 2019 and 2021 would each be 50 MW with a storage capacity of 50 MWh. These two are proposed to provide half of their capacity (50 MW) available to meet peak demand. The system in 2031 would be 100 MW x 100 MWh and would provide primarily energy capacity services in the summer (100 MW). (See, for example, p. 237)

VI. DTE'S EFFORTS TO INCLUDE ENERGY STORAGE IN THE IRP

Q. Have you reviewed DTE's IRP?

A. Yes.

Q. How did DTE evaluate new battery storage as a resource option?

A. The Company's initial technology screening described in the HDR document (Exhibit A-38) includes 4-hour duration lithium-ion battery storage as a suitable technology for further review. However, beyond the initial screening, battery storage was not adequately evaluated as a potential resource option to help met DTE's system needs.

[6] https://www.tep.com/wp-content/uploads/2016/04/TEP-2017-Integrated-Resource-FINAL-Low-Resolution.pdf

Q. What did DTE assume about storage costs?

A. DTE's assumptions about the future cost of advanced battery storage resources are significantly higher than both industry expectations and the cost assumptions used in the IRP proceedings I discuss above. DTE used a 26% decline in the cost over 5 years of installed lithium-ion battery resources. This is found in MECNRDCSCDE-2.1 ci 2017 Reference Scenario Aurora Inputs file, where lithium-ion batteries are listed with all-in capital costs beginning at $2,541 per KW for 2017. The Company used $/kwh in tables included in Exhibit A-38 and Exhibit A-4, where the storage systems were described as 4-hour duration. These values (given as "2015 cost basis") were $600 - $1500/kwh and $600/kwh respectively.

Comparison of the DTE costs and cost decline projection with other IRPs from the same time, and from the Lazard (and three other commercial projections) annual cost of storage report, shows DTE has used significantly higher cost numbers. Amongst the utility IRPs, DTE has projected less than half the cost decline (26% vs. 50%) of other utilities. The Lazard data for installed capital cost for 2017 reported as $1,338 per KW is just over half (52%) of the 2017 cost ($2,541) used by DTE in Aurora for a similar 4-hour configuration.

Q. Did DTE have adequate tools for modelling ancillary services costs and benefits?

A. Based on the testimony of Wojtowicz (APW-13), the absence of ancillary service capabilities in the model inputs provided by the Company, as well as the functional limits of the Strategist model, suggest that the Company lacks the means to model ancillary services.

Q. Did the Company's Strategist modeling include benefits of battery storage resources as a resource providing flexibility and ancillary services?

A. No, it appears the Company did not model the benefits of battery storage as a resource option with flexibility and ancillary services capabilities in Strategist. Despite a lengthy inventory of energy storage technology types, characteristics, and uses by HDR in Exhibit A-38, the Strategist model does not have the means to identify the cost savings and operational benefits from battery storage or other forms of flexible supply or demand.

The IRP report Appendix K (Exhibit A-5 at pages 47-48) overview of the Strategist model describes how Strategist functions to approximate the behavior and use of generation and subsequent consumption and cost of fuel. Strategist is described by the Company as "fulfilling a strategic planning role in that it requires less computer resources than more detailed production costing modules…Most module calculations are performed seasonally." (p 47) There is no suggestion that the Strategist model is sufficiently detailed (including hourly or sub-hourly calculations) to capture the need for, or benefits of, flexible resources and ancillary services as they are known and valued in wholesale markets and in the operation of the power system.

In essence, the Strategist model is not able to understand the unique stack of benefits that battery storage brings to the table. This shortcoming of the Strategist model means that

DTE was unable to quantify the potential benefits of including battery storage in its resource plan. This makes it impossible for DTE to claim with any quantitative certainty that including battery storage in its resource plan would not provide additional value to the company or its ratepayers.

Q. How does DTE represent energy storage in the evaluation and comparison of resources?

A. The Company presented in Exhibit A-38 a variety of information about the uses of energy storage, for example in table 5-1. This list shows 10 ways in which energy storage systems provide value to the Company and consumers. However, for the most part, the DTE modeling does not capture the benefits, value, and cost implications of energy storage resources.

Q. Could DTE have modeled storage more effectively?

A. Yes. The challenges in modeling the costs savings available to consumers from advanced battery storage resources are not unknown to DTE. In DTE's comments to MISO's Energy Storage Task Force in November 2017, the Company emphasizes the need for proper modeling of battery storage resources to accurately recognize and value the stack of benefits that this resource can provide. https://www.misoenergy.org/_layouts/MISO/ECM/Redirect.aspx?ID=265419 However, in its own modeling, DTE has made little effort to do this. The Strategist models' inability to assess capabilities and potential benefits of battery storage resources does not relieve the Company of its responsibility to make well-informed investment decisions, particularly given the examples I discuss above where utilities were able to perform more robust and appropriate analytics to evaluate battery storage resources.

Q. Are there specific benefits of battery storage resources that DTE identifies but does not properly evaluate?

A. Yes. Some of the values of energy storage that are named in Exhibit A-38, table 5-1, that are not included in the Company's modeling and comparison of resource options are ancillary services that I describe above – particularly frequency regulation and response, combined frequency regulation and response/resource adequacy, arbitrage, grid asset optimization and resilience, T&D system upgrade deferral, voltage support, and spinning reserve.

As an operator of a Local Balancing Area responsible for providing a larger range of services than just energy and capacity, DTE should have a responsibility to fully evaluate the potential for battery storage resources to provide these services and reduce the overall cost of system operations. Some of these uses of energy storage have value accruing to total revenue requirements for the utility, but not exclusively to the cost of generation. Transmission system improvements provided by energy storage may be partially captured in lower cost of generation. Distribution system upgrades provided by energy storage are less likely to be captured in analyses of generation costs. Regardless of the savings to consumers from these uses through T & D system budgets rather than generation expenses, the presentation in Exhibit A-38 of these uses cannot be dismissed as either speculative or irrelevant to the Company's filing. If one set of resources can do this at a lower expense than another set of resources, a resource plan review process should be able to make that distinction. DTE's IRP does not have this capability.

Q. How does the Company use the information in Exhibit A-38 in its analysis?

A. The Company does not use this information in its analysis. The Company has provided this inventory of valuable uses and then dropped these values from its analysis.

Q. Did DTE describe in its filing that ancillary services can be important to the IRP analysis?

A. Yes. First, the Company provided raw information on the benefits of storage providing ancillary services in tables and charts prepared by consultants and included as exhibits. More importantly, in Exhibit A-4 (IRP report, on page 178), the Company describes the need to account for ancillary service benefits in assessing the full value created by a technology. In the section titled "How Much Value It Is Creating in The Market" the Company explains, "While LCOE is a representation of costs, it does not show how much market value the technology is creating – either in the energy market, the capacity market, or the ancillary services market. The value that the different technologies create in these markets goes right to the bottom line in a revenue requirement view, which is ultimately the cost representation DTEE is using to compare the different resource plans."

Q. Did the Company make additional references to the value or cost of ancillary services in its filing?

A. Yes. In Exhibit A-4 (IRP report, page 178), DTE states that wind, due to its non-dispatchable nature, may cause "adverse effects in all three markets." Further, the Company states that "at high levels of wind penetration, additional integration may be required from other units" and "the costs for this integration may show up in the ancillary services value for the other types of units, therefore creating a type of negative ancillary value for wind, or added cost for integration." (Exhibit. A- 4, page 179). While I disagree with these statements about the ability to integrate wind energy resources, and in fact, DTE responded to discovery questions that showed it was not able to quantify these claimed impacts, they do highlight DTE's recognition of the value of ancillary services to system operations.

Additionally, in response to Question MECNRDCSCDE-1.3biii(3) K.L. Bilyeu indicates that the Company's cost-benefit analysis of other resources (such as energy efficiency) includes the value of ancillary services. This practice was not applied consistently in DTE's analysis of battery storage.

Q. Did the Company's review of resources and revenue requirements for resource plans reflect the market value created by energy storage in the ancillary services market?

A. No, the Direct Testimony of Angela P. Wojtowicz states that DTE did not include the ancillary services recognized by MISO in the Company's IRP process. (See page APW-13)

Q. Do you have an opinion as to how the failure to include these ancillary services impacts the Company's IRP?

A. The Company has undervalued battery storage by neglecting the reasonable analysis of these benefits. When the Company made comparisons of energy storage as a means of meeting its capacity needs and modeling the cost of serving the total energy and capacity needs of customers, it made an incomplete and inadequate comparison. Because battery storage resources represent a commercially available resource that can provide a range of recognized and valued benefits to the energy system, and because DTE did not adequately analyze the potential for these resources, independently or in combination with other resources, to reduce cost for its ratepayers, you cannot conclude that DTE's preferred plan represents the most reasonable plan for meeting future energy needs.

Q. Does this conclude your testimony?

A. Yes.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	)	Case No. U-18419

EXHIBIT OF

MICHAEL B. JACOBS

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

Jacobs Testimony and Comments in Regulatory Proceedings

Comments of the Union of Concerned Scientists
Federal Energy Regulatory Commission Docket No. RM18-1
Grid Reliability and Resilience Pricing
October 23, 2017

Comments of the Union of Concerned Scientists
Federal Energy Regulatory Commission Docket No. RM16-23
Electric Storage Participation in Markets
February 13, 2017

Comments of the Union of Concerned Scientists
Federal Energy Regulatory Commission Docket No. RM16-6
Essential Reliability Services and the Evolving Bulk-Power System
January 21, 2017

Comments of the Union of Concerned Scientists
Federal Energy Regulatory Commission Docket No. AD17-11
State Policies and Wholesale Markets
June 22, 2017

Protest of the Union of Concerned Scientists
Federal Energy Regulatory Commission Docket No. ER17-367
PJM Interconnection Tariff and Reliability Assurance Agreement
December 8, 2016

Testimony of the Union of Concerned Scientists
New Jersey Board of Public Utilities Docket No. EM1406058
In the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc.
November 14, 2014

Comments of the Union of Concerned Scientists
Maine Public Utilities Commission Docket No. 2014-00171
Notice of Inquiry into the Determination of the Value of Distributed Solar Energy Generation in the State of Maine
November 12, 2014

Testimony for First Wind/Maine Gen Lead, LLC.
Maine Public Utilities Commission Docket No. 2014-00048
EMERA MAINE: Request for Approval of Certificate of Public Convenience and Necessity for Construction of Transmission Line in Northern Maine

June 6, 2014

Comments of the Union of Concerned Scientists
Federal Energy Regulatory Commission Docket No. AD14-8
PJM Interconnection Report on Fuel Assurance Activities
March 20, 2014

Comments of the Union of Concerned Scientists
MN PUC Docket E-999/M-14-65
In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat.§216B.164, subd. 10 (e) and (f)
February 19, 2014

Comments of the Union of Concerned Scientists
MN PUC Docket E-999/M-14-65
In the Matter of Establishing a Distributed Solar Value Methodology under Minn. Stat.§216B.164, subd. 10 (e) and (f)
February 12, 2014

Testimony for First Wind/Maine Gen Lead, LLC.
Maine Public Utilities Commission Docket No. 2012-00589
Investigation into Reliability of Electric Service in Northern Maine
August 2, 2013

Comments of the Union of Concerned Scientists
Federal Energy Regulatory Commission 142 ¶ 61,049 Docket No. RM13-1
Small Generator Interconnection Agreements and Procedures
May 31, 2013

Comments of Xtreme Power Inc.
Federal Energy Regulatory Commission 146 ¶ 61,114 Docket No. RM11-24-000
Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies
August 22, 2011

Comments of Xtreme Power Inc.
Federal Energy Regulatory Commission 134 FERC ¶ 61,124 Docket No. RM11-7
Frequency Regulation Compensation in the Organized Wholesale Power Markets
May 2, 2011

Request for Rehearing of American Wind Energy Association
Federal Energy Regulatory Commission Docket Nos. ER06-407-000 and ER06-408-000
PJM Interconnection L.L.C Interconnection Service Agreement
March 24, 2006

Comments of American Wind Energy Association
Federal Energy Regulatory Commission Docket No. RM05-4-000
Interconnection for Wind Energy
Joint Report of the North American Electricity Reliability Council and the American Wind Energy Association
September 19, 2005

Comments of American Wind Energy Association
Federal Energy Regulatory Commission Docket No. RM05-4-000
Interconnection for Wind Energy and Other Alternative Technologies
Reply Comments
April 1, 2005

Comments of American Wind Energy Association
Federal Energy Regulatory Commission Docket No. RM05-4-000
Interconnection for Wind Energy and Other Alternative Technologies
White Paper on Wind Turbine Technology
March 16, 2005

Comments of American Wind Energy Association
Federal Energy Regulatory Commission Docket No. RM05-4-000
Interconnection for Wind Energy and Other Alternative Technologies
Initial Comments
March 2, 2005

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

DIRECT TESTIMONY OF

R. THOMAS BEACH

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

EXECUTIVE SUMMARY

Q: Mr. Beach, what is the purpose of your testimony?

A: My testimony presents recommendations on behalf of Vote Solar concerning the request of DTE Electric Company (DTE) for a Certificate of Necessity (CON) to build and operate a new natural gas-fired combined-cycle generating plant with a nominal capacity of about 1,100 megawatts (MW). This testimony respectfully asks the Commission to deny DTE's request.

Q: Please summarize your concerns with DTE's Proposed Project.

A: The gas plant is too risky and too expensive for DTE's ratepayers.

Q: Why is it too risky?

A: The uncertainty and volatility in future prices for natural gas, which comprise more than one-half of the life-cycle costs of the proposed gas plant, create significant risks to DTE's ratepayers. Although natural gas prices are low today, experience has shown that they are subject to significant uncertainty and volatility. In contrast, wind, solar, and efficiency resources have zero fuel costs and zero fuel price risk.

In my testimony, I calculate the added costs that DTE would incur to eliminate its fuel price risk, by fixing the price of natural gas to fuel the gas plant for the next 20 years; eliminating this risk would raise the gas plant's costs by 25%. DTE also has used an assumption that local gas market prices in Michigan will remain below the benchmark

Henry Hub price for the next 20 years, even though this is contradicted by the long-term gas forecasts on which the utility relies. Finally, DTE has subscribed to expensive new pipeline capacity to the Marcellus and Utica producing basins to provide a portion of the fuel for the gas plant. An affiliate of DTE is one of the sponsors of this pipeline. This conflicted commitment exposes ratepayers to the real risk that this capacity will be worth less than its cost in the long-run, as a result of overbuilding pipeline capacity out of these growing basins. In my testimony, I quantify all of these risks, which together could increase the costs of the gas plant by as much as 47% above what DTE has presented in its application for a CON.

Q: Have you formed an opinion as to what portfolio of resources would be less risky and less expensive than the gas plant?

A: Yes. A portfolio of renewable and efficiency (R / E) resources would provide the same capacity as the gas plant, at a significantly lower cost. I demonstrate that DTE could meet its capacity needs in 2022-2023 with a portfolio of wind and solar generation, plus incremental energy efficiency (EE) and demand response (DR) resources. My testimony shows that the Renewables / Efficiency (R / E) portfolio presented in Table ES-1 below will supply the same capacity that the gas plant would provide.

Table ES-1: *Vote Solar's Proposed Renewables / Efficiency Portfolio*

New renewable generation	**Nameplate Capacity (MW)**	**MISO Accredited Capacity (MW)**
Solar – fixed array	500	242
Solar – tracking	600	372
Wind	1,100	139
Incremental load reductions	**Load reduction (MW)**	**Reduction w/4% Reserve Margin (MW)**
2% per year EE	90	94
Demand response	251	261
Portfolio Total (MW)		**1,107**
Gas plant (MW)		***1,113***

Procurement of the R / E portfolio should begin immediately, at a measured pace designed to meet DTE's capacity needs in 2022-2023, which are driven by planned coal plant retirements. Near-term procurement of renewables has significant benefits: (1) it reduces the cost of the R / E portfolio by leveraging the availability of significant federal tax benefits that will expire (for wind) in 2020 and (for solar) in 2023; (2) the renewable resource additions needed for DTE to meet its commendable carbon reduction goals will be acquired at a more consistent pace over the next 20 years, and (3) as a result of the near-term capacity additions, DTE may be able to advance by one or two years the retirement of its River Rouge, St. Clair, and Trenton Channel coal units.

Q: What is the basis for your opinion that this scenario, which DTE failed to consider in its IRP, would have lower costs than its Proposed Project?

A: My testimony presents a detailed comparison between, first, the costs of the R / E portfolio and, second, DTE's stated gas plant costs (without considering the additional risks of the gas plant that are quantified in the first section of the testimony). For the solar capacity, I consider data on utility-scale and distributed solar costs that is more recent, more detailed, and more authoritative than what DTE used. I include the likely impact of the pending Section 201 trade case that may impose tariffs on some imported solar panels. DTE's own analysis shows that implementing a goal of 2% annual load reductions through energy efficiency programs is cost-effective; other intervenors will show that even more could be accomplished with EE programs. My assumptions for incremental demand response programs are based on just 50% of the "low" potential for incremental, cost-effective demand response programs identified in the Commission's new report, released last fall, on Michigan's demand response potential. To the extent that my R / E portfolio does not produce the same amount of energy or capacity as the gas plant on an annual, monthly, or hourly basis, I have priced out the small differences using DTE's forecast for MISO market prices. I also consider the added costs for ancillary services to integrate higher levels of renewable resources on DTE's system. Based on these cost assumptions, my R / E portfolio is $339 million (13%) less expensive than the gas plant over the forecast period, as summarized in **Table ES-2** below.

Table ES-2: *Summary of R / E Portfolio Costs vs. Gas Plant (2018-2042)*

Resource	**Capacity (MW)**		**Energy (GWh)**		**NPV Costs (2018-2042)**		
	Nameplate	**Accredited**	**Total GWh**	**Levelized GWh/year**	**$MM**	**$/MWh**	**$/kW-year**
R/E Portfolio:							
Solar	1,100	623	39,630	1,353	$947	$67	
Wind	1,100	139	80,427	2,783	$1,468	$50	
EE @ 2%	94	94	6,436	424	$53	$12	
New DR	261	261			$115		$44
Net Market	(151)	(151)	(11,706)	(771)	($349)	($43)	
Integration			39,737	3,790	$79	$2	
Total	**2,555**	**1,107**	**114,787**	**3,790**	**$2,314**	**$58**	
Gas Plant:							
Total	**1,113**	**1,113**	**114,787**	**3,790**	**$2,653**	**$67**	
Difference: Savings from R/E Portfolio					**$339 MM or 13% NPV**		

Q: Did you do anything to verify this conclusion?

A: Yes. My conclusion that the R / E portfolio is less expensive than the gas plant is robust, as I show by examining sensitivities to important assumptions, including the gas price forecast and the capacity factor of the gas plant. The conclusion that the R / E portfolio is more economic is also substantiated by the results when the portfolio is analyzed in the Strategist model that DTE used.

Q: Are there other benefits to ratepayers from the R / E scenario you discuss in your testimony?

A: Yes. The portfolio of renewables and efficiency will provide more jobs for Michigan, as well as significant environmental and reliability benefits. The R / E portfolio generates significantly more new jobs in southeast Michigan than the proposed gas plant, by a margin of almost ten-to-one in construction jobs and four-to-one in long-term employment in ongoing operations.

The clean energy resources in the R / E portfolio also will provide significant, quantifiable benefits from reductions in the emissions of both criteria pollutants and carbon. A very conservative estimate of the benefits of the R / E portfolio from reduced costs to comply with air emission regulations is $13 million per year. The societal benefits from the R / E portfolio's lower emissions of greenhouse gases and criteria pollutants, compared to the gas plant, are much larger – $367 million per year over the 2018-2042 period from improved health and mitigating the damages of climate change. Further, large societal benefits can be realized from accelerating the retirement of the coal units, largely as a result of the substantial drop in SO_2 emissions.

Q: Is the scenario you propose more reliable than DTE's proposed gas plant?

A: Yes. A diversified portfolio of small, widely dispersed renewable generation projects is inherently more reliable than a single gas plant in one location, because the impact of an outage at an individual wind or solar unit will be far less consequential than an outage at a major central station power plant. Moreover, most electric system interruptions are the result of weather-related transmission and distribution system outages; new central station generation does not reduce this risk. However, distributed renewables, located at the point of end use and matched with on-site storage, can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer any type of outage. Thus, a vibrant and growing market for distributed solar and wind resources is an important foundation piece for a more reliable and resilient grid.

TABLE OF CONTENTS

I. INTRODUCTION

Q: Please state for the record your name, position, and business address.

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

Q: Please describe your experience and qualifications.

A: My experience and qualifications are described in the attached *curriculum vitae* (CV), which is **Ex. ELP-58 (RTB-1)** to this testimony. As reflected in my CV, I have more than 35 years of experience on resource planning and ratemaking issues for natural gas and electric utilities. I began my career in 1981 on the staff at the California Public Utilities Commission (CPUC), working on the initial implementation of the Public Utilities Regulatory Policies Act of 1978 (PURPA). While at the CPUC, I also served as policy advisor to three commissioners, and played a central role in the restructuring of California's natural gas industry. Since leaving the Commission in 1989, I have had a private consulting practice on energy issues and have appeared, testified, or submitted testimony, studies, or reports before state regulatory commissions in more than twenty states. My CV includes a list of the formal testimony that I have sponsored in state regulatory proceedings concerning electric and gas utilities. Prior to this professional experience, I earned an undergraduate degree in English and physics from Dartmouth

College and a Master's degree in mechanical engineering from the University of California at Berkeley.

Q: Please describe more specifically your experience on resource planning and pricing issues concerning both natural gas-fired and renewable resources.

A: Throughout my career, I have represented qualifying facilities (QFs) under PURPA on a wide range of issues involving both gas-fired cogeneration projects and the full range of renewable QF technologies. This experience includes testimony on power purchase agreements and avoided cost pricing issues in state regulatory proceedings in California, Idaho, Montana, Nevada, North Carolina, Oregon, Utah, and Vermont. I also have extensive experience on natural gas transportation and pricing issues, particularly related to serving natural gas-fired power plants. I have worked extensively on public policy issues related to the development and deployment of wind and solar generation, including the issue of assessing the capacity value of these variable renewable resources. This work includes evaluating the costs and benefits of solar – both small, distributed solar systems and large, utility-scale units. In 2006-2007, I testified on cost-effectiveness and represented the solar industry in the development of the implementation details for the California Solar Initiative, California's successful ten-year incentive program for rooftop solar systems. With respect to cost-effectiveness issues concerning renewable distributed generation (DG), I have sponsored testimony on net energy metering (NEM) and solar economics in California and ten other states, and since 2013 I have co-authored benefit-cost studies of NEM or solar DG in California, Colorado, Arizona, Arkansas, New Hampshire, and North Carolina. I also co-authored the chapter on Distributed Generation Policy in *America's Power Plan*, a report on emerging energy issues, which was released in 2013 and is designed to provide policymakers with tools to address key questions concerning distributed generation resources.[1]

In the Upper Midwest, in 2014 I testified before the Minnesota commission on behalf of Geronimo Solar, LLC in support of Geronimo's winning bid to provide new solar generating capacity on Xcel Energy's Northern States Power system.[2] Geronimo won a portion of this solicitation in competition with gas-fired combined-cycle and simple-cycle generation.

Q: Have you previously testified or appeared as a witness before this Commission?

A: No, I have not.

Q: On whose behalf are you testifying in this proceeding?

A: I am appearing on behalf of Vote Solar, the Environmental Law & Policy Center, the Ecology Center, the Solar Energy Industries Association, and the Union of Concerned Scientists. Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a

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1 This report has been published in *The Electricity Journal*, Volume 26, Issue 8 (October 2013). It is also available at http://americaspowerplan.com/ .

2 See OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240. My testimony was filed September 27 and October 18, 2013.

mainstream energy resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has more than 70,000 members throughout the United States, including members and supporters in DTE's Michigan service territory.

Q: Are you sponsoring any exhibits?

A: Yes, I am sponsoring the following exhibits:

- Exhibit ELP-58 (RTB-1) CV of R. Thomas Beach
- Exhibit ELP-59 (RTB-2) DTE Responses to Selected Data Requests
- Exhibit ELP-60 (RTB-3) State of Michigan Demand Response Potential Study
- Exhibit ELP-61 (RTB-4) Annual Capacity Balance for the R/E Portfolio
- Exhibit ELP-62 (RTB-5) Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

II. BACKGROUND

A. DTE's Proposed Gas Plant

Q: Please describe briefly the new natural gas-fired combined-cycle unit that DTE has proposed.

A: DTE proposes to build a nominal 1,100 MW gas-fired combined cycle generating facility at its existing Belle River site. The capital cost for the gas plant would be $989 million, and it would enter service in June 2022.[3] The gas plant would use new, advanced, H-class gas turbines to reduce the plant's heat rate in combined-cycle operations, and would include duct burners downstream from the gas turbines to increase project output (albeit with reduced efficiency). Project costs also include $20.2 million for construction of a gas pipeline lateral to access nearby major gas pipelines plus commitments to upstream firm transportation and storage capacity, as well as $29.3 million for new electric interconnection facilities to tie into the existing electric transmission grid.[4]

B. Statutory Requirements for a Certificate of Necessity

Q: Please summarize the statutory requirements that a utility must satisfy for the Commission to grant a Certificate of Necessity (CON) for a major new generating facility.

A: Section 6(s) of 2016 PA 341 provides that an electric company that proposes to build a new generation facility that represents investment costs of more than $100 million may submit an application to this Commission seeking one or more certificates of necessity finding that the new plant is needed and its costs should be recovered through the utility's rate base. Generally, DTE bears the burden of proof to show the Commission that:

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[3] See DTE Testimony of I.M. Dimitry, at pp. IMD-21 and IMD-34, D. Swiech at p. DS-13 to DS-14, and D. O. Fahrer at pp. DOF-4 and DOF-7.

[4] See, generally, DTE Testimony of W.H. Damon, at pp. WHD-14 to WHD-16, and E.P. Weber, at pp. EPW-9 to EPW-10. The added gas lateral, transportation, and storage costs are included in the natural gas cost forecast. The electric transmission interconnection costs are not included in the gas plant's $989 million capital cost. See DTE Testimony of D. O. Fahrer at p. DOF-8.

a. [it] has **demonstrated a need** for the power that would be supplied by the proposed electric generation facility . . . through its approved integrated resource plan . . .;

b. the proposed electric generation facility will **comply with all applicable state and federal environmental standards, laws, and rules**;

c. **the estimated cost of power from the proposed electric generation facility is reasonable**;

d. the proposed electric generation facility represents **the most reasonable and prudent means of meeting the power need relative to other resource options for meeting power demand**, including energy efficiency programs, electric transmission efficiencies, and any alternative proposals submitted by existing suppliers of electric generation capacity or by other intervenors; and

e. to the extent practicable, the construction of a new facility in Michigan is completed using **a workforce composed of Michigan residents.**[5]

III. DTE'S NEED FOR NEW CAPACITY AND ASSOCIATED ENERGY

A. Coal Plant Retirements

Q: DTE's need for new capacity in the 2022-2023 time frame is driven principally by the planned retirements of aging coal units at the River Rouge (Unit 2), St. Clair (Units 1-4, 6, and 7), and Trenton Channel (Unit 9) power plants in the 2020-2023 time frame. Do you agree that these retirements are prudent?

A: Yes. Further, as I will show below, these retirements may be accelerated by one to two years, if DTE pursues the alternative resource portfolio that I present in this testimony.

[5] See MCL 460.6s(4); also, DTE Testimony of I.M. Dimitry, at pp. IMD-11 to IMD-12.

B. DTE's Long-term Commitment to Reduce Carbon Emissions

Q: In May 2017, DTE announced a long-term commitment to reduce its existing carbon emissions by 80% by 2050.[6] Do you support this goal?

A: Yes. To accomplish this goal, DTE must phase out its use of coal and add significant amounts of renewable resources that will both replace the retired coal capacity and, ultimately, also displace gas-fired generation. However, the resource plan that DTE has proposed to reach this goal heavily backloads the renewable generation additions (and the carbon reductions) into the years after 2030, with two large gas plants being built in 2023 and 2029 before most of the renewable capacity is added. The 2023 gas plant is the subject of this application. DTE's renewable additions under its proposal are shown in **Figure 1**. In comparison, the portfolio of renewable and efficiency additions that I have proposed would begin the renewable build-out in the near future, in order to take advantage of the lower-cost renewables available with the existing tax credits. The resulting build-out of renewables is shown in **Figure 2**, with the renewable build-out after 2025 reduced to reflect the renewables added from 2018-2025. In reaching DTE's carbon reduction goal, my portfolio adds new solar capacity at a more consistent pace over time, which should result in a more manageable and flexible trajectory of resource additions than what the utility has proposed.

6 See DTE Testimony of K.J. Chreston, at p. KJC-10 and B.J. Marietta, at p. BJM-15. DTE has modeled a 75% reduction by 2040 as an intermediate step to the 2050 goal. See pp. KJC-30, KJC-31, KJC-57, and BJM-15.

Figure 1: *DTE Renewables Additions*

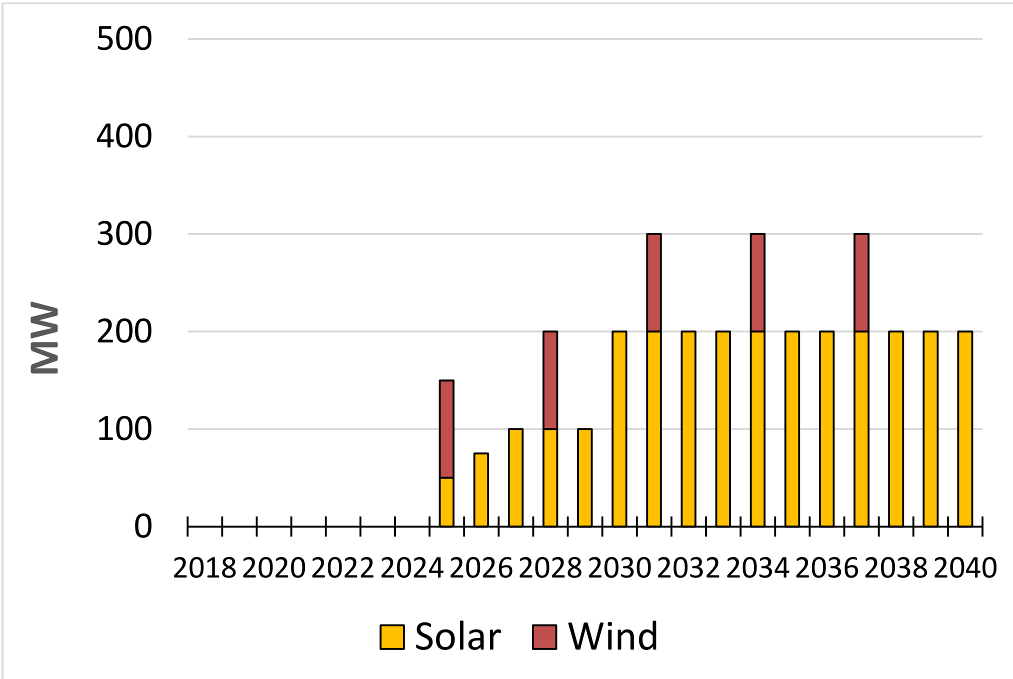
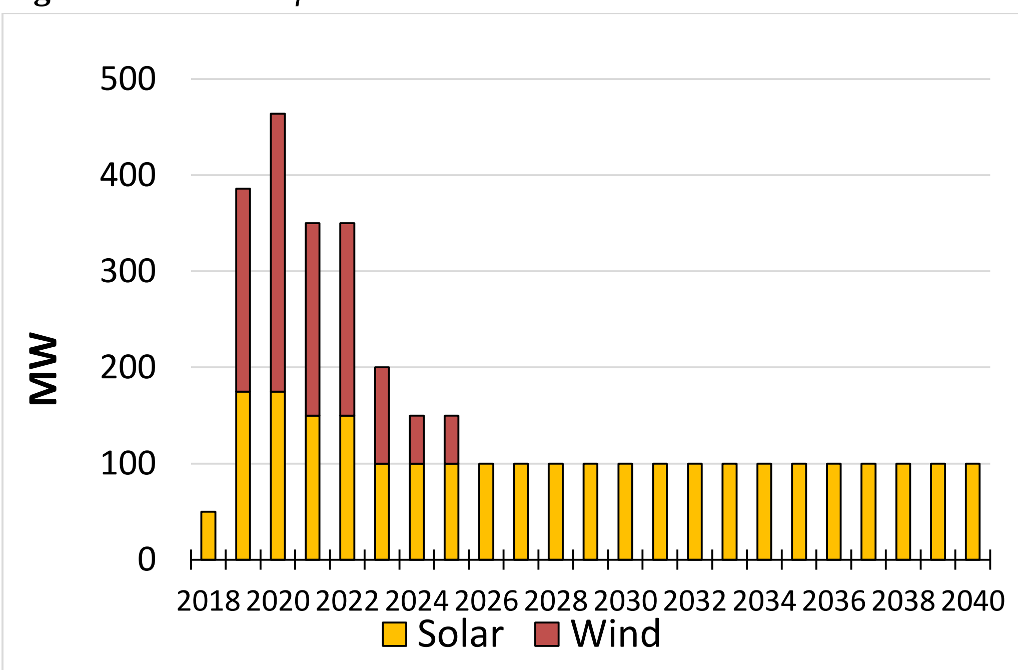


Figure 2: *R / E Portfolio – Renewables Additions*



IV. THE COMMISSION SHOULD REJECT A CON FOR DTE'S GAS PLANT

Q: Please summarize the reasons why the Commission should reject a CON for DTE's proposed gas plant.

A: There are three principal reasons for rejecting DTE's requested CON:

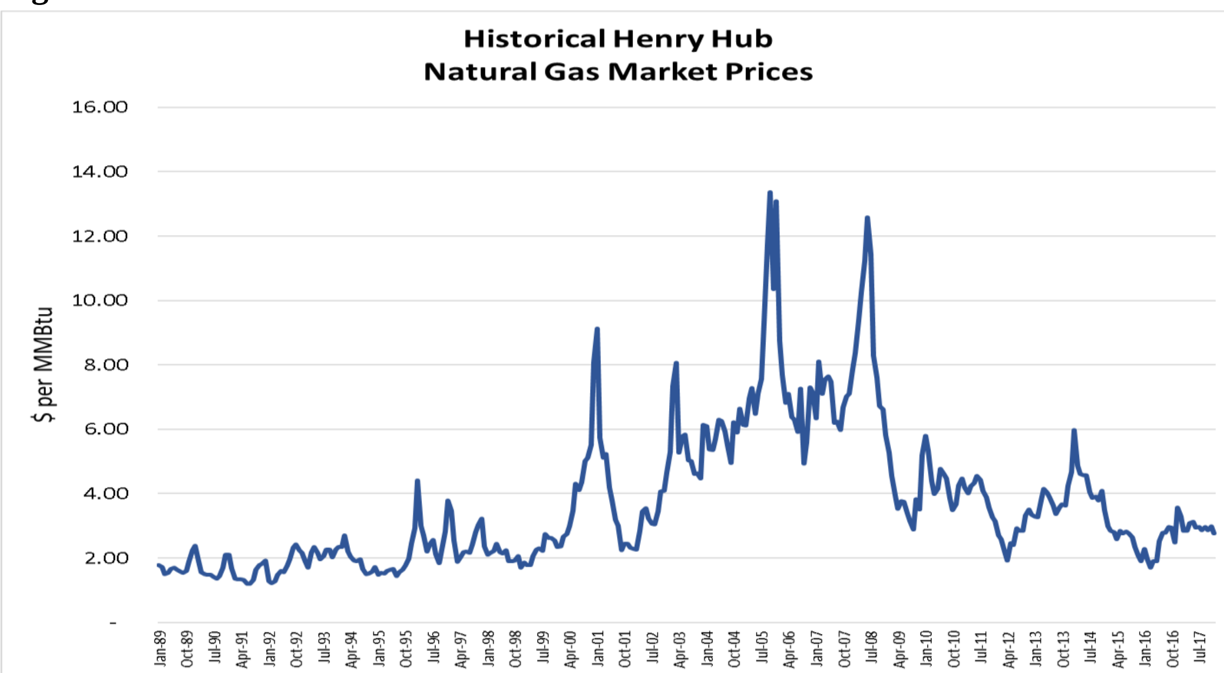
1. **The gas plant will be too expensive and too risky**. DTE has failed to explain how it will mitigate the price risks associated with a major new gas plant – in particular, the risk of significantly higher costs for ratepayers resulting from future uncertainty and volatility in the price for natural gas fuel. The costs to eliminate this uncertainty would add substantially to the gas plant's costs.
2. **A portfolio of wind, solar, and demand-side resources will be less expensive and less risky**, with costs that are lower, more certain, and less volatile than the gas plant.
3. The alternate portfolio of renewable and efficiency resources offers additional benefits compared to the gas plant:
   a. **More jobs** for Michigan,
   b. A more **reliable and resilient electric grid**, and
   c. Benefits from **reduced emissions of carbon and other criteria pollutants**.

A. The Gas Plant Will Be Too Expensive and Too Risky.

Q: What is the principal risk to ratepayers from the construction of a large gas plant?

A: The major risk is the price for the natural gas fuel, which comprises 57% of the expected levelized cost of the DTE gas plant, based on the utility's long-term gas cost forecast. However, natural gas prices are volatile and uncertain, as exemplified by the periodic spikes in natural gas prices. Such spikes have occurred regularly in the U.S. over the last several decades, as shown in the plot in **Figure 3** of historical benchmark Henry Hub gas prices.

Figure 3



Source: Natural Gas Intelligence monthly average Henry Hub prices.

The most recent major spike in natural gas prices occurred from January to March 2014 as a result of the "polar vortex" event of prolonged, very cold temperatures in the Midwestern and Eastern U.S.

Q: Is there significant uncertainty in the natural gas cost forecast that DTE has presented in this case?

A: Yes. DTE's long-term gas forecast is based on forward prices at the benchmark Henry Hub market for the next five years (2018-2022), then transitioning to a long-term forecast from Pace Global (Pace) of Henry Hub and producing basin prices. There are several issues with the forecast that DTE has used. First, DTE's reliance on more than one or two years of forward prices is questionable due to the thinly-traded forward markets after the initial two years. For example, **Table 1** shows the open interest in Henry Hub forward contracts on November 10, 2017. 99% of the open contracts are for the first two years plus one month, i.e. through calendar 2019.

Table 1: *Henry Hub Open Interest on November 13, 2017*

Period	Dec 17	2018	2019	2020	2021	2022	2023	2024	2025
Prior Day Open Interest	177,645	1,023,325	128,709	8,718	1,556	215	131	2	1
As %	13%	76%	10%	1%	0.1%	0.0%	0.0%	0.0%	0.0%

Second, other forecasts that are contemporaneous with the Pace projection are available, and are significantly higher. For example, the Energy Information Administration's *2017 Annual Energy Outlook* (*2017 AEO*) is the U.S. government's primary forecast of future natural gas prices. I have calculated the expected costs for the DTE gas plant under a sensitivity that uses current Henry Hub forward prices for 2018-2019, then transitions over four years to the *2017 AEO* forecast. I note that the Commission recently adopted the use of EIA's regional 2017 forecast of delivered natural gas prices for use in setting the long-term avoided costs for Consumers Energy.[7] This sensitivity increases the levelized cost of power from the gas plant by 15%, from $67 to $76 per MWh.

Q: You have noted that natural gas prices are uncertain and volatile. Can you quantify the additional cost to DTE's ratepayers that results from this uncertainty and volatility?

A: Yes, I can. The cost to ratepayers of the uncertainty and volatility in future natural gas prices is the additional cost that the utility would incur today to fix the price of natural gas for the gas plant over the planning horizon, thus eliminating all uncertainty and volatility in the new plant's cost of natural gas.

Q: How could you fix the price of the plant's future gas supplies?

A: One could contract today for future natural gas supplies at today's forward gas prices, and then set aside in risk-free investments (U.S. Treasury notes) the money needed to buy that gas in the future. This would eliminate from the outset the uncertainty in future gas costs. However, there is an additional cost of this approach, compared to purchasing gas on an "as you go" basis over time and using the money that did not have to be set aside for alternative investments that yield a higher return, which I assume to be the utility's

[7] See Order dated November 21, 2017 in Case No. U-18090, at pp. 25-26. In that case, the utility recommended using a short-term forecast based on forward market prices, escalated using the year-to-year change in the 2017 EIA forecast; see p. 13.

weighted average cost of capital (WACC). This difference between returns at the utility's WACC and risk-free returns on U.S. Treasuries is the measure of the future market risks of purchasing natural gas on an as-you-go basis versus fixing the gas price upfront. The added cost of foregoing these higher returns is the cost to ratepayers of eliminating fuel price uncertainty, or, conversely, the benefit to ratepayers when they displace natural gas with renewables whose fuel is free and whose costs are more certain upfront. Avoiding the cost of fuel price uncertainty is a significant benefit provided by an alternative portfolio of renewables and efficiency which replaces the natural gas that would fuel the gas plant.

Q: Have you calculated the cost of fuel price uncertainty for the proposed gas plant?

A: Yes, I have, for the first twenty years of the plant's operations. The key inputs to this calculation are (1) the commodity portion of DTE's base gas cost forecast (i.e. the portion of DTE's gas costs that are subject to market uncertainty), (2) U.S. Treasuries at current yields (as the cost of risk-free investments), (3) DTE's WACC (as the return that could be realized if the money were not spent fixing the cost of gas), and (4) the gas plant's heat rate of 6,300 Btu per kWh (to express the results in dollars per MWh of generation). This calculation follows the methodology used in the *Maine Distributed Solar Valuation Study*, a 2015 study commissioned by the Maine Public Utilities Commission and authored by Clean Power Research that estimated the benefits to Maine of new renewable resources that displace gas-fired generation.[8] The benefits calculated in the Maine study included the reduction in the cost of fuel price uncertainty when renewable generation displaces natural gas.

For the proposed DTE gas plant, the result of this calculation is that the cost to DTE's ratepayers of eliminating the fuel price uncertainty in DTE's gas plant is an additional $17 per MWh, or $86 million per year, over the 2023-2042 period. Consideration of this factor increases the costs of the gas plant by 25%.

Q: Please comment on DTE's testimony that it intends to structure its gas supply contracts "to minimize price volatility."[9]

A: In discovery, we questioned DTE on how it planned to reduce volatility in its gas commodity costs. In response, DTE said that it will "consider long-term, fixed price gas supply contracts" to achieve this.[10] However, the utility has not executed any such contracts, and does not provide any details on the volume or term of such contracts or on whether such contracts would add costs.[11] DTE provided examples of its existing forward gas contracts, but these do not extend more than three years into the future and

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[8] The Maine study is available at http://www.maine.gov/mpuc/electricity/elect_generation/documents/MainePUCVOS-ExecutiveSummary.pdf.

[9] DTE Testimony of D. Swiech, at p. DS-8.

[10] See DTE response to ELPCDE-1.41a, included in Exhibit RTB-2.

[11] See DTE response to ELPCDE-1.41b-d, included in Exhibit RTB-2.

do not have fixed prices.[12]

Q: Is there also uncertainty in other elements of DTE's natural gas cost forecast?

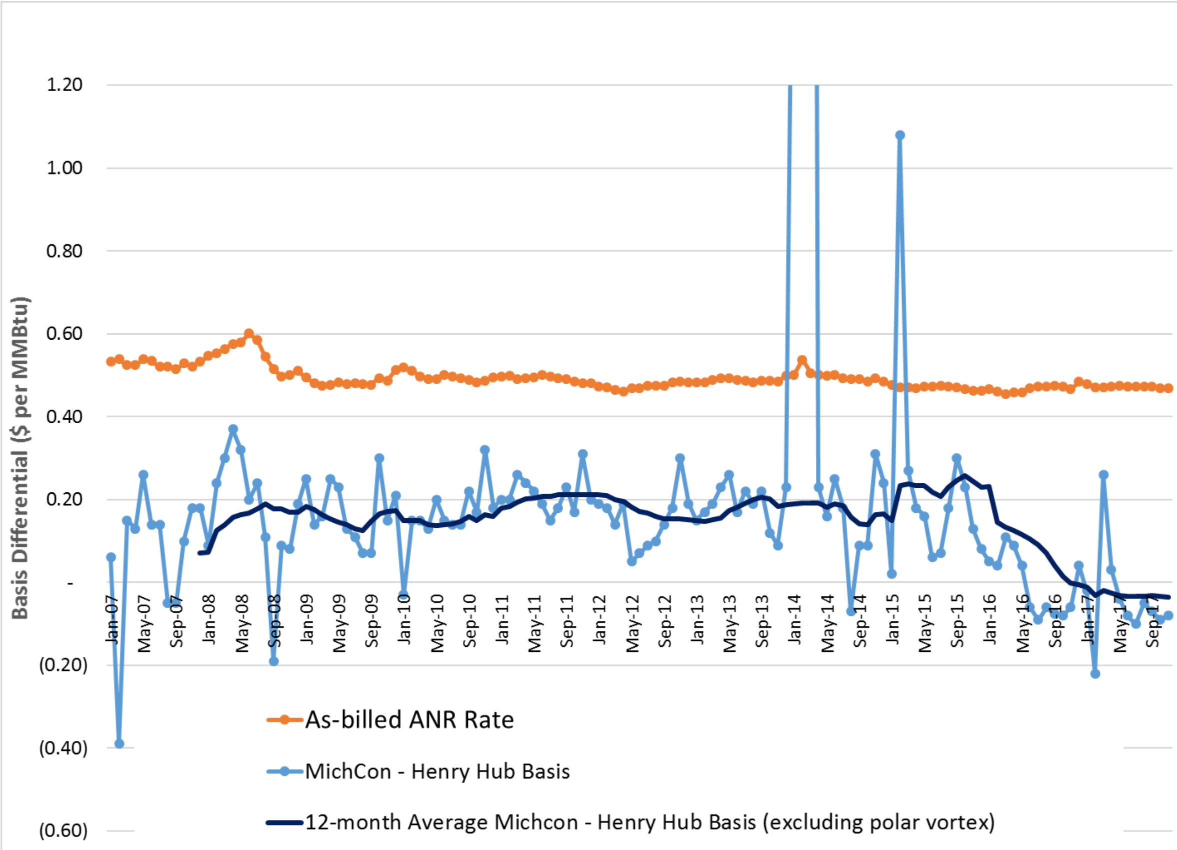
A: Yes. The utility projects that the price differential, or "basis," between the benchmark Henry Hub market and the nearest market hub, the Michcon City-gate, will be a negative -$0.13 per MMBtu (i.e. the Michcon City-gate will have a lower price) in 2023. This basis is taken from a sample of the gas forward markets on just one day – May 10, 2017.[13] DTE expects this basis to escalate over the long-term at the rate of inflation, i.e. to become more negative.

Q: How does the Henry Hub / Michcon City-gate basis that DTE has used compare with the historical record on this basis?

A: The -$0.13 per MMBtu basis that DTE assumes is significantly lower than the basis typically experienced in the market over the last 10 years, as shown in **Figure 5**.

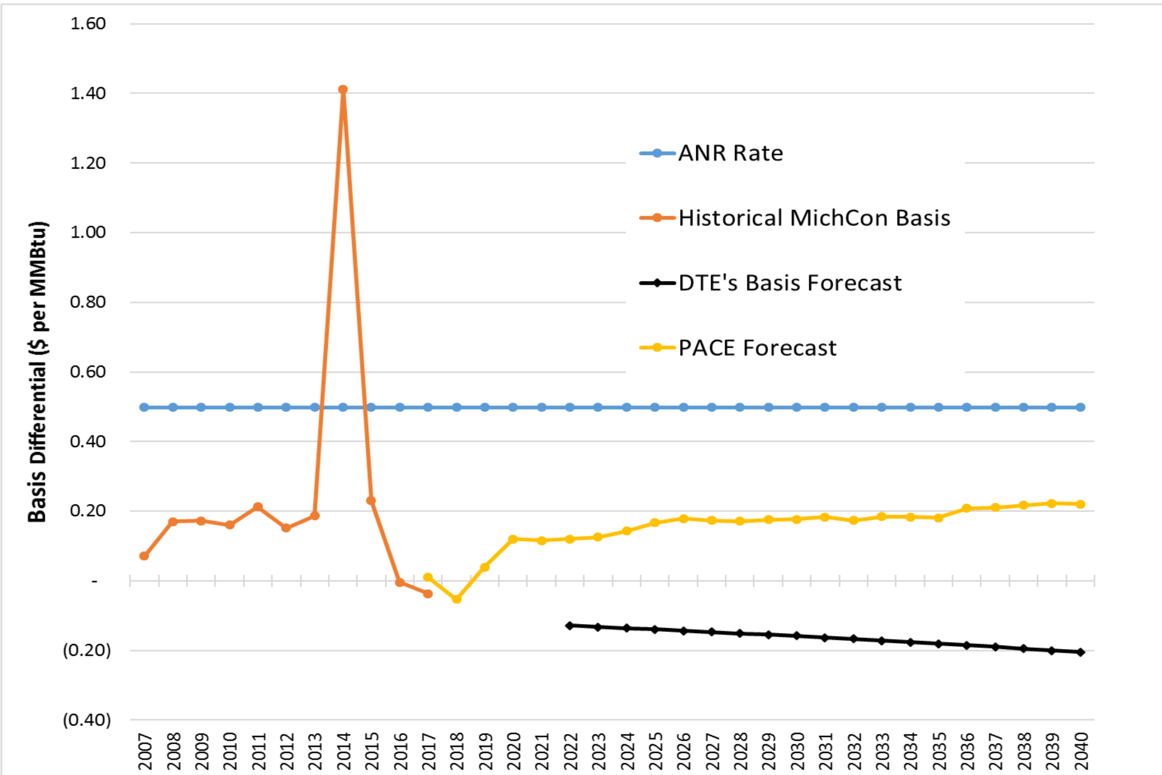
[12] See DTE response to ELPCDE-1.42a-b, included in Exhibit RTB-2.
[13] See DTE response to ELPCDE-2.4b, included in Exhibit RTB-2.

Figure 5: *Michcon City-gate to Henry Hub Basis Differential ($/MMBtu)*



DTE's gas cost forecast is thus too low if the increasing demand for natural gas in the Upper Midwest results in a return to the higher basis differentials seen in prior years. For example, over the last ten years not including 2014 (which featured the very high basis during the polar vortex event of January - March 2014), the Henry Hub / Michcon City-gate basis has averaged a positive +$0.13 per MMBtu. DTE's long-term gas fundamentals forecast from Pace Global projects a similar positive basis differential going forward to 2040, as shown in **Figure 6**. DTE ignored the PACE forecast in favor of the very low, one-time value from May 10, 2017.[14] The use of this higher basis would increase the cost of the gas plant by 3%.

Figure 6: *Michcon City-Gate to Henry Hub Past & Forward Basis ($ per MMBtu)*



Q: Are there new pipelines planned to serve southeast Michigan that might bring new gas supplies into the area?

A: Yes. DTE has entered into a precedent agreement for 30,000 to 75,000 Dth per day of pipeline capacity on the new NEXUS pipeline that would provide a new pipeline route connecting southeastern Michigan to the Marcellus and Utica Shale producing basins in

[14] DTE admits that it did not use the Pace forecast for the Henry Hub – Michcon basis in its response to ELPCDE-2.4h, included as Exhibit RTB-2.

western Pennsylvania and Ohio. The higher amount of pipeline capacity (75,000 Dth per day) is contingent on DTE's operation of new gas-fired generating facilities, i.e. on the completion of the new gas plant.[15]

Q: How does DTE's commitment to NEXUS impact the risks of the gas plant for ratepayers?

A: As noted above, the new gas supplies from NEXUS may offset the upward pressure on the market basis that could result from the incremental demand from new gas-fired generation facilities such as the gas plant. However, the fact the DTE is likely to hold capacity on NEXUS increases the risks that the gas plant will result in above-market transportation costs for DTE's ratepayers, costs that are not included in DTE's gas forecast. Due to the NEXUS commitment, DTE's ratepayers are not just exposed to the risks of the volatility and uncertainty of the gas commodity market; they also are exposed to the risks of the markets for pipeline capacity in the region – specifically, the risk of whether new pipeline capacity from Michigan to western Pennsylvania and Ohio will be economic. NEXUS capacity is only economic if the basis differential between (1) southeast Michigan (at the Michcon City-gate or Dawn markets) and (2) the Marcellus/Utica basins is greater than the full cost of transportation on NEXUS, including the reservation charges that DTE will pay. This full cost is expected to be

[15] The higher amount of capacity would become effective upon the in-service date of a combined cycle plant with at least 680 MW of capacity and a 70% capacity factor, conditions which are satisfied by DTE's proposed gas plant. See DTE response to ELPCDE-1.36, included in Exhibit RTB-2.

$0.695 per Dth plus 1.32% fuel,[16] or a total of $0.75 per Dth assuming a $4 per MMBtu cost of fuel. If the Marcellus-to-Michcon City-gate basis is less than the full cost of NEXUS capacity, these new supplies will not be economic in DTE's service territory.

Q: In discovery, DTE provided a 3Q 2017 forecast from ICF which projects that the price of Marcellus gas in southwest Pennsylvania (presumably at the Dominion South hub) will be $0.90 to $1.45 per MMBtu less than the Henry Hub, throughout the period from 2018-2038.[17] Do you think that this forecast is realistic?

A: No. It is well-known and often-observed in the natural gas industry that the addition of new pipeline capacity to a growing producing basin tends to collapse the basis differential between the basin and the consuming markets at the downstream end of the new pipeline.[18] Once the cumulative pipeline capacity from a basin exceeds the production in the basin, competition will reduce the market value of pipeline capacity from the basin to a fraction of the full, "as-billed" rate for firm pipeline capacity to the basin.[19] Such a "basis collapse" has been observed repeatedly in North American producing basins that have grown rapidly for past boom periods, such as the San Juan basin in New Mexico, the Rocky Mountain region, and the Western Canadian

[16] See DTE response to ELPCDE-1.37, included in Exhibit RTB-2.

[17] See DTE response to ELPCDE-1.40.

[18] DTE agrees that the addition of the Rover and NEXUS would reduce the basis differential between the Marcellus and the Michcon City-gate. See DTE response to ELPCDE-2.2.

[19] The fact that basis differentials tend to be much less than the full pipeline rate on unconstrained routes is shown in both Figures 5 and 6. Both figures compare the basis from the Michcon City-gate to the Henry Hub versus the full as-billed rate on the ANR pipeline that connects these two markets.

Sedimentary Basin. As just one example of many, the basis differential from the Rocky Mountain supply region to the Henry Hub declined from $2 to $3 per MMBtu in 2007-2008 to just $0.11 per MMBtu over the last six years (2012-2017), as a result of pipeline expansions completed out of the Rockies to both eastern and western markets.[20]

Q: What accounts for this propensity for pipeline expansions to exceed the production capacity of the producing basins which they access?

A: The regulatory structure and incentives for new interstate gas pipelines encourages pipeline developers to overbuild pipeline capacity to new and growing producing basins. These factors include:

- The FERC's longstanding **market-based policies for certificating new pipelines** do not require project proponents to demonstrate a need for the new capacity; instead, they can show significant market interest (for example, from executed precedent agreements) for the pipeline's capacity and must be willing to bear the risk of subscribing that capacity.
- In the gas industry, there are **no regional bodies responsible for planning** and rationalizing the amount of pipeline capacity built to a region with growing gas production. This differs from much of the nation's electric system, where there are regional transmission organizations (RTOs) with responsibility for planning and determining the need for new bulk electric transmission.

[20] Based on *Natural Gas Intelligence* monthly average gas prices from the Opal, Wyoming market center and the Henry Hub.

- Pipeline developers can **market capacity to both ends of the pipe** – on one hand to utilities and end use customers who may not have a full understanding of the economics of producing gas in the new, rapidly-growing basin, and on the other hand to producers who seek downstream market access but may lack firm customers or a firm knowledge of the likely future demand for gas in the consuming market. The result of this information asymmetry at both ends of the pipeline can be the oversubscription and overbuilding of pipeline capacity.
- The FERC has granted **attractive returns** in the neighborhood of 14% as the basis for the recourse rates of new interstate pipelines. Such returns significantly exceed those available to regulated utilities, which has attracted the unregulated affiliates of utilities to participate as partners in the new pipeline projects serving their utility affiliates. This equity involvement by the utility affiliate raises the concern that this financial interest in the success of the pipeline project may cause the utility to overcommit to the new capacity or not to adequately analyze the alternatives to their gas-fired generation resources that would be an "anchor" market for the new capacity.

This propensity to overbuild capacity to fast-growing basins is widely acknowledged in the natural gas industry. The CEO of Energy Transfer Partners, a major pipeline company, commented recently that "the pipeline business will overbuild until the end of time."[21]

Q: Are there more pipelines proposed to be built out of the Marcellus and Utica basins than the expected production capacity of these basins?

A: Yes. A number of studies, from sources as diverse as Moody's Investor Services (2014), Bloomberg New Energy Finance (2016), and Oil Change International (2016), have projected that pipeline takeaway capacity from the Marcellus and Utica basins will begin to significantly exceed the basins' production in 2018-2019.[22]

Q: Your final factor that contributes to pipeline overbuilding is the participation of utility affiliates as developers of new pipelines. Is this factor – the potential for a conflict of interest between DTE's affiliates and DTE's ratepayers – a particular concern in this case?

A: Yes, it is, because an unregulated affiliate of DTE is one of the sponsors of the NEXUS project.

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[21] Kelcy Warren, CEO of Energy Transfer Partners, in the second quarter 2015 earnings call, August 15, 2015.

[22] These results are reported in the Institute for Energy Economics and Financial Analysis's report *Risks Associated with Natural Gas Pipeline Expansion in Appalachia* (April 2016), at pp. 10-12. Available at http://ieefa.org/wp-content/uploads/2016/04/Risks-Associated-With-Natural-Gas-Pipeline-Expansion-in-Appalachia-_April-2016.pdf.

Q: If the long-term value of NEXUS capacity is 50% of the pipeline's full as-billed rate, how much would that increase the gas costs for the new gas plant?

A: The above-market pipeline costs of NEXUS would increase the gas plant's fuel costs by about $0.37 per MMBtu, resulting in a 5% increase in the gas plant's overall costs.

Q: Has this Commission approved DTE's cost recovery for its subscription to NEXUS capacity?

A: No, it has not. In its decision in DTE's 2016 and 2017 fuel cost recovery dockets, the Commission stated that its approval of fuel expenses in those cases specifically did not include recovery of any costs associated with the NEXUS project.[23]

Q: Does DTE specifically ask for approval of the NEXUS capacity subscription in its request in this case?

A: No. My understanding of the scope of DTE's request in this docket is that it is limited to a Certificate of Necessity for the gas plant, including the gas pipeline lateral that would interconnect the plant to existing nearby large-diameter gas transmission lines,[24] but not for any upstream interstate pipeline capacity such as the NEXUS commitment.

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[23] See the Commission's January 12, 2017 order in Case No. U-17920 and December 20, 2017 order in Case No. U-18143, at pp. 7-9. Also see DTE response to ELPCDE-7.14, included in Exhibit RTB-2, stating that in September 2017 DTE filed its 2018 PSCR Plan (Case No. U-18403), requesting Commission review and approval of the expenses associated with DTE Electric's agreements with NEXUS. See also DTE Testimony of D. Swiech, at pp. DS-7 to 8 and DS-13 to 14.

[24] DTE Testimony of D. Swiech, at p. DS-14.

Q: Please summarize the cumulative impact of all of the risks you have discussed and quantified on the overall costs for the DTE gas plant.

A: **Table 2** presents the quantifiable impacts of these risks, which together could increase the 20-year levelized costs of the gas plant from 2023-2042 by as much as 47%. Not all of these impacts may materialize; however, there is a significant potential for the gas plant's costs to be much higher than DTE has estimated.

Table 2: *Quantifiable Risks Impacting Gas Plant Costs*

Base Gas Plant Costs	**Cost (20-year levelized)** *$ per MWh*	
Capital revenue requirement	30.30	
Base fuel costs (DTE forecast)	36.40	
Total	**66.70**	
Risk Factors Impacting Gas Plant Fuel Costs	**Cost Change (20-year levelized)**	
	$ per MWh	*%*
Revised Henry Hub forecast	9	15%
Fuel price volatility	17	25%
Higher basis	2	3%
Above-market cost of NEXUS capacity	4	5%
Total	**32**	**47%**
Revised Gas Plant Costs	**$98 per MWh**	

Q: Table 2 shows that the gas plant's levelized costs from 2023-2042 are $67 per MWh. You have discussed above the issues associated with the plant' fuel costs. Do you accept DTE's estimates for the capital and O&M costs, and the modeled annual output, of the gas plant?

A: Yes, I do. However, I have several reservations about the utility's showing on the costs and expected output for the proposed gas plant. First, DTE's Strategist model does not isolate the revenue requirements for the proposed gas plant from additional gas units that the model selects in years after 2023, or from other capital additions from 2018-2022. In discovery, DTE declined to provide the revenue requirements for the gas plant alone.[25] In this application, DTE is requesting a CON only for the gas plant to come online in 2022, not for additional units further in the future. Thus, DTE should bear the burden to identify clearly the ratepayer costs for the plant for which they are requesting approval. I have attempted to calculate the revenue requirements for the 2022 gas plant alone using the same model that I used to calculate the levelized costs for the wind and solar resources; however, this model may understate the gas plant's costs because it does not include a full representation of ratepayer costs during the construction process.

Second, DTE is proposing to use a new class of advanced gas turbines, for which there is little operating experience to date. DTE is proposing a 1.1 GW plant, when only 8 GW of similar turbines have been developed.[26] DTE's witness Mr. Damon asserts that large frame combined cycle generating stations operating today have a typical availability of over 87% based on 2011-2015 data.[27] However, it is unclear whether this availability is based on the very limited operating history of this new class of turbines, because the 2011-2015 period that Mr. Damon cites appears to predate the first installations of this new class of turbines. Mr. Damon cites just one project in Oklahoma that became

[25] See DTE response to ELPCDE-3.8.
[26] See DTE Testimony of D.O. Fahrer, at p. DOF-9.
[27] DTE Testimony of W.H. Damon, at p. WHD-15.

operational in May 2017, as well as two projects in Texas that "recently completed commercial startup and commissioning operation."[28] In discovery, the utility, citing confidentiality, did not make available the operating data supporting the asserted 87% availability for this class of turbines.[29]

B. A Portfolio of Renewables and Efficiency Resources Provides the Same Capacity as the Gas Plant, and Will be Less Expensive and Less Risky.

1. The R / E Portfolio – capacity and output

Q: Please describe the alternative portfolio that you believe would be superior to the proposed gas plant, in terms of both costs and risks.

A: A superior alternative to the gas plant would be a portfolio of 2,200 MW of new renewable generation sited in Michigan, plus additional capacity and energy savings from cost-effective expansions of DTE's energy efficiency (EE) and demand response (DR) programs. This renewables / efficiency (R / E) portfolio has four major elements:

1. 1,100 MW (nameplate) of new solar generation, including:
   - 200 MW of distributed solar
   - 300 MW of utility-scale fixed-tilt systems
   - 600 MW of utility-scale tracking arrays
2. 1,100 MW (nameplate) of new wind projects
3. Increase DTE's EE target to 2.0% load reductions per year, from DTE's planned 1.5% per year.
4. Add 251 MW of incremental demand response capacity by 2023, based on 50% of the Realistic Low potential in the new *State of Michigan DR Potential Study*.

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[28] *Ibid*., at p. WHD-20.
[29] See DTE response to ELPCDE-3.11a and 3.11b, included in Exhibit RTB-2.

Q: Please explain how you have calculated the capacity which the R / E Portfolio would provide to DTE.

A: **Solar.** I have calculated the accredited capacity value of the 1,100 MW of new solar capacity. The capacity value of solar resources is less than its nameplate capacity, because solar will not be producing at full nameplate during the summer afternoon hours when demand peaks. I use the National Renewable Energy Laboratory's (NREL) PVWATTS tool to calculate the average hourly profiles of fixed and single-axis tracking arrays at several locations in southeast Michigan.[30] The accredited capacity for such these solar output profiles, as a percentage of nameplate capacity, is based on the methodology adopted by the Midcontinent Independent System Operator (MISO).[31] The MISO's rules for resource adequacy (RA) establish that the solar capacity value is the capacity factor of solar facilities from hour ending (HE) 3 p.m. to 5 p.m. Eastern Standard Time in June, July, and August, with a default of 50% of nameplate until actual output is available. Using this rule for the accreditation of solar capacity, I calculate that

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[30] See http://pvwatts.nrel.gov/. In running PVWATTS, I assume an inverter loading ratio (ILR) – used to convert the DC output capacity of the solar array to a nameplate AC capacity – of 1.2 for fixed arrays and 1.3 for tracking systems. The higher ILR for tracking arrays produces a "flatter" output profile across a broader set of daylight hours, thus increasing the capacity value of the array based on the MISO accreditation criteria. There is a trend in utility-scale solar facilities toward the use of tracking systems with higher ILRs to achieve higher capacity values. See Lawrence Berkeley National Laboratory (LBNL), *Utility-scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (September 2017), at pp. 12-13, available at https://emp.lbl.gov/publications/utility-scale-solar-2016-empirical (hereafter, "*Utility-scale Solar 2016*"). Also see Footnote 25 below on the Aurora project in Minnesota.

[31] See MISO Business Practice Manual BPM-011-r16, Section 4.2.3.4.1.

the capacity value of solar facilities in southeastern Michigan will be 49% of nameplate for fixed arrays and 63% of nameplate for single-axis trackers.[32]

Wind. The hourly output profile of these resources is from NREL's System Advisor Model for wind resources.[33] I then used MISO's rules to determine the accredited capacity value of the 1,100 MW of wind resources in my R / E portfolio. As a base case, I use a capacity value of 12.6% of nameplate for MISO Zone 7, from MISO's most recent study of wind capacity value across its footprint. As an alternative to this value, the MISO system-wide average capacity value for wind resources is 15.6% of nameplate.[34]

Energy Efficiency. My portfolio assumes that cost-effective EE programs will achieve a 2% per year reduction in energy use, which is 0.5% per year more than DTE now plans. These incremental EE resources primarily reduce energy use, but DTE's modeling of this assumption from its *2016 Integrated Resource Plan* (*2016 IRP)* also shows that this incremental EE results in a 90 MW lower need for coincident peak capacity.[35]

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[32] Geronimo Solar's Aurora project in Minnesota is an example of the prior application of the MISO capacity accreditation method to a solar project in the Upper Midwest that was designed primarily as a capacity resource. The Aurora project uses an ILR of 1.3 and tracking arrays at multiple distributed sites across the Northern States Power system to achieve a capacity value of 71% of nameplate.

[33] See https://sam.nrel.gov/. I used SAM to model a wind farm in eastern Michigan with 2 MW turbines.

[34] See MISO, *Planning Year 2017-2018 Wind Capacity Credit* (December 2016), at pp. 4 and 14.

[35] See DTE Testimony of K. L. Bilyeu, workpapers for his Tables 7 and 8.

Demand response. 2016 legislation required the Commission to conduct an assessment of the potential use of demand response (DR) in Michigan for use as an input into integrated resource plan modeling scenarios.[36] The Commission recently released this new study of the demand response potential in Michigan.[37] The Commission's report shows that significant additional cost-effective capacity reductions from DR are achievable in Lower Michigan, particularly from various types of time- and demand-sensitive rates. This "realistic achievable" DR potential for Lower Michigan is summarized in Table 5-2 of the study, reproduced below:

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%

In contrast, DTE's application includes about 100 MW <u>less</u> DR capacity than included in the last *IRP*, based on declining participation in DR programs. DTE does not appear to have assessed whether these participation rates could be improved. Furthermore, the utility's DR projections do not include the incremental reductions in peak loads that are achievable through new rate and tariff structures such as Time-of-Use (TOU), Critical

[36] 2016 PA 341 Sec. 6t.

[37] See *State of Michigan Demand Response Potential Study*, released September 29, 2017. Available at http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406250--,00.html. Hereafter, "*Michigan DR Potential Study*." This report is included as Exhibit **RTB-3**.

Peak (CPP), and Real-Time (RT) rates. My portfolio assumes that DTE could expand its existing DR programs, with cost savings for its ratepayers, by just 50% of the "Realistic Low" potential identified in the *Michigan DR Potential Study*.[38] This modest addition to DTE's DR programs would add 251 MW of capacity by 2023.

Q: Please summarize the capacity that your R/E portfolio would add by 2023.

A: **Table 3** summarizes the capacity that my R / E portfolio would add to the DTE system, showing that it would add an amount of capacity comparable to the proposed gas plant.

Table 3: *Renewables / Efficiency Portfolio*

New renewable generation	**Nameplate (MW)**	**MISO RA Criteria (%)**	**RA Capacity (MW)**
Solar – fixed array	500	49%	242
Solar – tracking	600	63%	372
Wind	1,100	12.6%	139
Incremental load reductions	**Load reduction (MW)**	**Reserve Margin @ 4% (MW)**	**RA Capacity (MW)**
2% per year EE	90	4	94
Demand response	251	10	261
Portfolio Total (MW)			**1,107**
Gas plant			***1,113***

Q: What would be the timing of the capacity additions from the R/E portfolio?

A: The R / E portfolio would begin to add significant new wind and solar capacity immediately, in 2019, in order to take advantage of the existing federal tax credits for wind and solar projects. This reduces the cost of the R / E portfolio. In addition, the

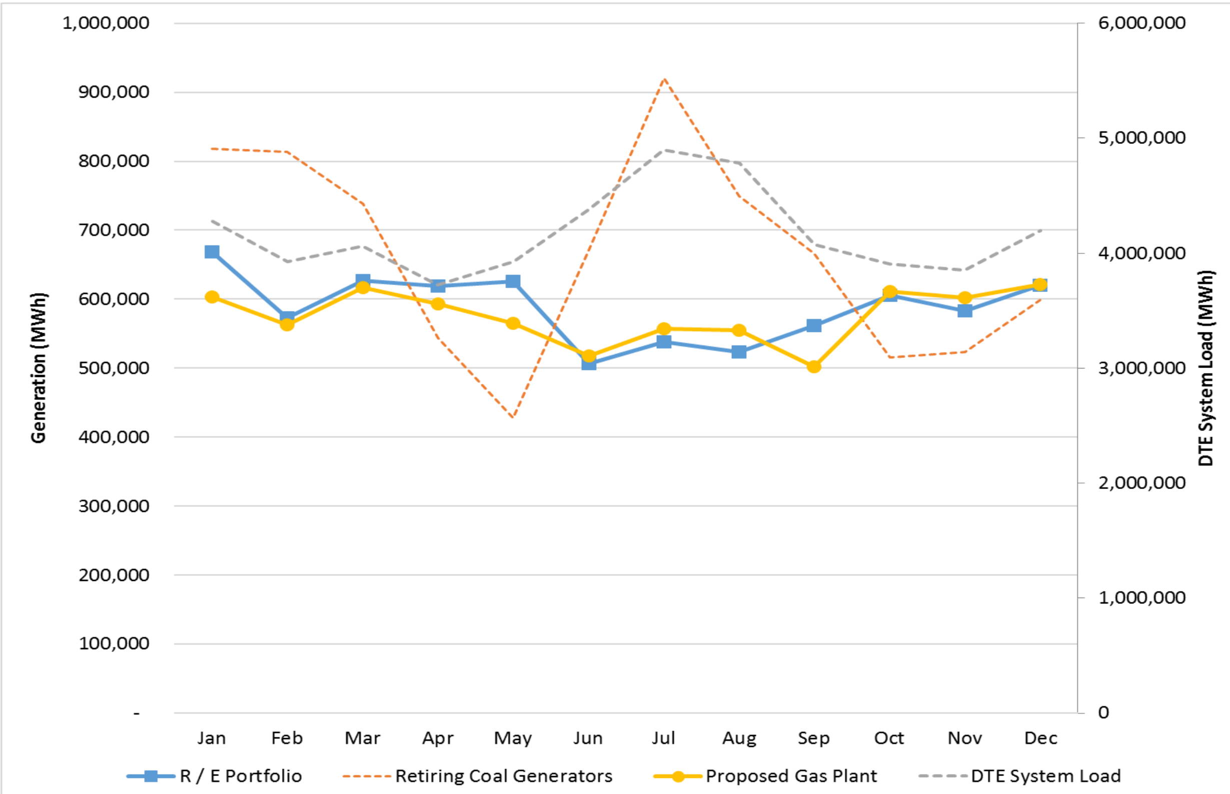
[38] Thus, I take 50% of the percentages shown in the last line of Table 5-2, and apply these percentages to DTE's expected peak demands in these years.

near-term procurement of renewable generation spreads out over more than 20 years the acquisition of new renewables – particularly the solar capacity – needed to meet DTE's long-term carbon reduction goal, rather than backloading the acquisition of most renewable capacity into the 2030-2040 decade. This more measured and consistent procurement of renewables will provide DTE with more flexibility to meet its long-term goal. The near-term acquisition of renewables also will supply DTE with new capacity before 2022-2023 that could allow DTE to accelerate the retirement of its coal plants before the schedule DTE proposes in its application. Finally, as discussed in the next section, this early procurement of new renewable capacity results in lower costs and reduced risks for DTE ratepayers. I include as **Ex. ELP-61 (RTB-4)** a chart of the annual capacity balance for the R/E portfolio that can be compared to the capacity balances that DTE provides for its 2016 and 2017 reference scenarios.

Q: DTE has proposed a gas plant that would operate initially at a capacity factor of approximately 71% to replace coal plants that historically have operated at capacity factors of 38% to 52%. Solar and wind capacity factors are lower – about 40% for wind and 20% for solar – and vary seasonally. Would the R / E portfolio you have proposed have a similar generation profile as the gas plant?

A: Yes, it would. In terms of monthly and seasonal output, **Figure 7** shows the expected outputs of the gas plant (solid yellow line) in the first year of operation and the R / E portfolio (solid blue line) when its capacity is fully in place. The R / E portfolio includes the expected monthly energy savings from the incremental EE programs that I propose. The figure also shows the profiles of DTE's system load (gray dashes) and the coal plants that will be retiring by 2023 (orange dots). The R / E portfolio provides the same capacity as the gas plant, with a monthly profile of energy production that is very similar to the expected output of the gas plant. Small amounts of sales into or purchases from the MISO energy market can be used to match the gas plant's output exactly, and I have included such sales or purchases in the costs of the R/ E portfolio. I have also compared the expected hourly output profiles for the gas plant and the R / E portfolio over an annual period, and have adjusted the costs of the market sales or purchases used to balance the two portfolios based on the market value of the small differences in the expected hourly profiles for the two portfolios.

Figure 7: *Monthly Profiles of the Gas Plant and the R / E Portfolio*



2. Costs of the R / E Portfolio

Q: Please discuss the basic strategy that you employ to develop an R / E portfolio that is less expensive than the proposed gas plant.

A: My approach to designing the R / E portfolio is, first, to leverage the existing (and expiring) wind and solar tax credits with an early build-out of renewables that takes advantage of these credits. Second, I develop incremental energy efficiency and demand response resources in a measured way that is both feasible and more cost-effective than the gas plant. As noted above, the R / E portfolio provides the same capacity as the gas plant and comparable amounts of energy. The early procurement of additional capacity also provides the flexibility to accelerate the retirement of the coal plants that DTE proposes to close by 2023, should that be desirable.

Q: What are the key assumptions that you used to calculate the costs of new solar generation in southeast Michigan?

A: I used reported capital costs through 2016 from Lawrence Berkeley National Laboratory's (LBNL) 2017 reports on actual utility-scale and distributed commercial solar costs in the U.S.[39] I extended this actual cost data to 2017-2022 using the changes in solar costs over this period from a recent forecast prepared by Wood Mackenzie's Greentech Media in conjunction with the Solar Energy Industries Association (GTM/SEIA).[40] These capital cost assumptions are shown in **Table 5** below.

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[39] See LBNL, *Utility-scale Solar 2016*, at p. 20, and LBNL, *Tracking the Sun X* (August 2017), at p. 41, available at https://emp.lbl.gov/publications/tracking-sun-10-installed-price.

[40] See GTM Research, *PV System Pricing H1 2017: Breakdowns and Forecasts* (June 2017), at 7, 34, 41, and 43, available at https://www.greentechmedia.com/research/report/pv-system-pricing-h1-2017#gs.tHjJR6c. As discussed in LBNL, *Utility-scale Solar 2016*, at p. 20, LBNL uses a "top down" cost reporting methodology that is more comprehensive than GTM's "bottom up" approach to costing and forecasting. To compensate for the possible costs that are not captured in GTM's forecasts, we have increased GTM's forecasts in all years by the observed ratios of LBNL's 2016 reported costs to GTM's 2016 reported costs.

Q: Why did you not use the same forecast of solar costs that DTE employed?

A: DTE's testimony states that it used a forecast of utility-scale solar costs from Navigant Consulting's confidential report *U.S. Distributed Renewables Deployment Forecast*.[41] This forecast should not be given any weight, for the following reasons:

- The forecast was published in the second quarter of 2016, and thus is far older than the more recent data from LBNL and GTM/SEIA that I used.
- [redacted]

[41] I obtained this report in response to data request ELPCDE-1.28.

[redacted]

The testimony of Mr. Kevin Lucas for the Solar Energy Industries Association, Environmental Law & Policy Center, the Ecology Center, Vote Solar, and the Union of Concerned Scientists provides a more detailed discussion of the problems with the Navigant forecast and the other projections of renewable costs that DTE has used for various modeling exercises relevant to this case.

[redacted]

Q: On Friday, September 22, 2017, the U.S. International Trade Commission (ITC) voted to approve a finding that imports of cheap solar panels have caused injury to domestic solar manufacturers. Did you adjust your forecast to incorporate the possible impact of the trade case on the cost of solar panels and cells?

A: Yes. The four members of the ITC have proposed a range of remedies, in terms of tariffs that would apply for up to the next four years (assumed to be 2018-2021). I have assumed that the remedy that the Administration ultimately adopts will be the remedy suggested by two of the four commissioners – a new tariff on solar imports starting at 30% of module costs in 2018, and declining by 5% in each of the next three years. The Administration has until January 2018 to decide on a final policy. I have applied the expected tariff to increase the assumed cost of modules in my forecast of solar costs from 2018-2021, even though there are reports that solar companies have been stockpiling modules and some imports may be exempt from the tariff. Further, the history of similar tariffs on imports suggests that any adopted tariff may be in place for less than four years, due to retaliation from foreign countries that manufacture panels or as a result of legal action before the World Trade Organization, both of which could lead to reductions or removal of any tariffs that the U.S. adopts. For this reason, I believe that my forecast of the impacts of the trade case on solar costs is reasonable, and even conservative in over-estimating the potential impacts. I also modeled a sensitivity case in which there are no tariffs on imported modules, and solar costs are lower as a result.

Q: What are the other assumptions that you have used to calculate the costs of solar generation?

A: These assumptions are summarized in **Table 4**. The capacity factor assumptions are based on PVWATTS output profiles for solar facilities located at several locations in southeast Michigan, as discussed above.

Table 4: *Solar Cost Assumptions*

Cost Parameter	Value	*Source*
Capacity factor: fixed arrays	18.5%	*PVWATTS for SE Michigan sites*
Capacity factor: tracking arrays	22.0%	*PVWATTS for SE Michigan sites*
Performance degradation	0.5%/year	*Industry standard assumption*
Annual O&M	$18/kW-yr	*2018 value; escalates at 2.5%/yr*
Property taxes	0.75%	*Workpaper KJC-479; DTE response to ELPCDE-3.6a*
Insurance	0.5%	
Federal Solar Investment Tax Credit	30% to 2020, 26% in 2021, 22% in 2022, 10% from 2023	*Current law*
Debt/Equity	50/50	*Workpaper KJC-479; also see LBNL Utility-scale Solar 2016, at p.41 for similar values.*
Debt Cost	4.6%	
Equity Cost	10.2%	
WACC (after tax)	6.5%	

Q: Based on the above assumptions, how did you calculate the cost of generation from new utility-scale solar facilities?

A: I used a pro forma model of the levelized cost of energy from utility-scale renewable generation projects owned by third-party independent power producers (IPPs) to calculate expected PPA prices for new utility-scale solar projects, based on the assumptions in Tables 4 and 5. This model was developed by the consulting firm Energy &

Environmental Economics (E3) for the utilities in the Western Electricity Coordinating Council (WECC), and has been used widely to project renewable PPA prices.[43] The results are shown in bold in **Table 5** below.

Table 5: *Solar PPA Costs*

DG System Type	Cost Metric	2017	2018	2019	2020	2021	2022
Fixed Utility-scale	*PV Cost $/Watt-dc*	*1.26*	*1.09*	*1.04*	*0.99*	*0.95*	*0.93*
	PPA Price $/MWh	**64.44**	**58.04**	**56.42**	**59.10**	**61.86**	**73.40**
Fixed Utility-scale (trade sensitivity)	*PV Cost $/Watt-dc*	*1.26*	*1.18*	*1.11*	*1.05*	*0.99*	*0.93*
	PPA Price $/MWh	**64.44**	**61.62**	**59.20**	**61.75**	**63.79**	**73.40**
Fixed DG Commercial	*PV Cost $/Watt-dc*	*1.50*	*1.29*	*1.20*	*1.13*	*1.06*	*1.03*
	PPA Price $/MWh	**100.21**	**88.64**	**84.24**	**87.32**	**89.95**	**107.21**
Fixed DG Commercial (trade sensitivity)	*PV Cost $/Watt-dc*	*1.50*	*1.95*	*1.81*	*1.68*	*1.57*	*1.48*
	PPA Price $/MWh	**100.21**	**92.22**	**87.02**	**89.53**	**91.89**	**107.21**
Tracking System	*PV Cost $/Watt-dc*	*1.42*	*1.24*	*1.17*	*1.12*	*1.07*	*1.05*
	PPA Price $/MWh	**63.49**	**57.27**	**55.05**	**57.98**	**60.54**	**72.45**
Tracking System (trade sensitivity)	*PV Cost $/Watt-dc*	*1.42*	*1.33*	*1.24*	*1.17*	*1.11*	*1.05*
	PPA Price $/MWh	**63.49**	**60.53**	**57.58**	**59.99**	**62.30**	**72.45**

I made two further adjustment to the costs of solar DG serving commercial customers: I assume that these facilities will be located on the DTE distribution system, will deliver their output to on-site or nearby loads, and thus will allow the utility to avoid (1)

[43] This *WECC Generation Costing Tool* model is available on the E3 website at https://ethree.com/public_projects/renewable_energy_costing_tool.php.

additional line losses at the transmission level and (2) upstream costs for high-voltage transmission service, in an amount equal to the accredited capacity of these solar DG units. As a measure of these avoided transmission costs, I used the MISO Network Integration Transmission Service tariff rate for ITC, which owns the transmission system serving DTE. These avoided losses and transmission costs reduce the cost of commercial DG solar by about $20 per MWh.

Q: What are the key assumptions that you used to calculate the costs of new wind facilities in Michigan that could supply DTE?

A: For new wind generation, I generally accept DTE's assumed trajectory of the future capital costs of new wind farms. Other important assumptions used to develop my projections for wind PPA prices are summarized below in **Table 6**.

Table 6: *Wind Cost Assumptions*

<table>
<tr><th>Cost Parameter</th><th>Value</th><th>Source</th></tr>
<tr><td>Capacity factor</td><td>38%</td><td>Lower than DTE's 41%</td></tr>
<tr><td>Annual O&M</td><td>$32/kW-yr</td><td>2016 value; escalates at 2.5%/yr</td></tr>
<tr><td>Property taxes</td><td>0.75%</td><td rowspan="2">Workpaper KJC-479; DTE response to ELPCDE-3.6a</td></tr>
<tr><td>Insurance</td><td>0.06%</td></tr>
<tr><td>Wind PTC</td><td>$23.0/MWh in 2017,
$18.4/MWh in 2018,
$13.8/MWh in 2019,
$9.2/MWh in 2020</td><td>Current law</td></tr>
<tr><td>Debt/Equity</td><td>50/50</td><td rowspan="4">Workpaper KJC-479; also see LBNL Utility-scale Solar 2016, at p.41 for similar values.</td></tr>
<tr><td>Debt Cost</td><td>4.6%</td></tr>
<tr><td>Equity Cost</td><td>10.2%</td></tr>
<tr><td>WACC (after tax)</td><td>6.5%</td></tr>
</table>

The wind capacity factor assumption of 38% is lower than DTE's assumed 41%, and considers that a portion of future wind projects may not be located in the state's best wind resource areas. The best wind resources areas in the state, such as Huron County, already have seen significant wind development and have experienced some local opposition to further wind projects. Based on the assumptions in Table 6, I used the E3 WECC model to calculate for the cost of incremental wind PPAs. These results are shown in **Table 7** below.

Table 7: *Wind PPA Costs*

	2017	**2018**	**2019**	**2020**	**2021**	**2022-25**
Capital Cost ($/watt)	*1.641*	*1.533*	*1.526*	*1.519*	*1.416*	*1.409*
PPA Price ($/MWh)	**37.97**	**35.03**	**41.12**	**47.21**	**56.46**	**56.56**

Q: Please discuss the costs for the additional energy efficiency resources included in the R / E Portfolio.

A: DTE's IRP included a scenario with 2.0% annual energy savings, instead of the 1.5% annual savings which DTE used in its preferred IRP scenario and in this application. However, the DTE *IRP* shows that 2.0% EE savings per year is also cost-effective, and provides additional conserved energy and capacity in the near-term (2018-2027). The cost of this incremental conserved energy is low, about $12 per MWh, and these additional EE programs also provide an associated 94 MW of capacity. The testimony of other intervenors, such as the Natural Resources Defense Council (NRDC), will show that the potential for cost-effective energy efficiency savings is even greater than DTE's 2.0% annual savings. Thus, this is a conservative assumption for EE savings.

Q: You have also included additional capacity from demand response programs. Please discuss the costs and reasonableness of including these additional DR resources.

A: The Commission's new study of the demand response potential in Michigan – the *Michigan DR Study* – projects that there is significant additional potential for DR programs to reduce peak demand in Lower Michigan. Assuming just one-half of the DR capacity in the study's Realistic Achievable – Low scenario would result in an incremental 251 MW of demand response capacity in DTE's territory. Based on the program costs summarized in the Commission's study, the cost of these new DR programs is $44 per kW-year.

Q: The R / E portfolio uses market sales or purchases to ensure that the portfolio provides the same amount of capacity and energy as the gas plant, measured as the same levelized GWh as the gas plant over the forecast period. Please discuss the timing, magnitude, and cost of these assumed market sales or purchases.

A: Due to the early procurement of renewables to leverage tax credits, there are market sales of energy and excess capacity from the R / E portfolio in 2018-2022, before the gas plant would begin operations. These market sales would be reduced if there is an acceleration of the retirement of the coal units that DTE would shut down before 2023. After 2022, whether market purchases or sales are needed for the R / E portfolio to match the output of the gas plant depends on the gas plant's assumed capacity factor. In my base case, which uses the gas plant's capacity factor from the Strategist run of the 2016 reference case, there are generally market purchases from 2023-2028 and market sales from 2029 on. All of these differences in the timing of energy and capacity additions, compared to the gas plant, are priced out using the energy and capacity market prices assumed in the DTE application for the 2017 reference case. In the base case, these market sales contribute to reducing R / E Portfolio costs by 13%.

As a sensitivity, I also looked at an assumption that the gas plant operates at a constant capacity factor of 71% throughout the forecast period, based on the first-year output from DTE's Strategist modeling.[44] In this sensitivity case, a small amount of market purchases, with a modest (+8%) impact on R / E portfolio costs, are needed in order to produce the same levelized GWh as the gas plant over the forecast period.

Q: Do the market purchases in the R / E portfolio also expose DTE's ratepayers to some risk of volatile electric market prices linked to volatile natural gas prices?

A: The only exposure occurs if the R / E portfolio does not supply as much energy as the gas plant, such that the R / E portfolio must be supplemented with net purchases of energy

[44] From DTE's Strategist output file for the 2016 reference scenario.

from the MISO market. My analysis shows that the R / E portfolio requires supplemental market purchases of energy only if one assumes that the gas plant operates at a 70% or higher capacity factor for the entire forecast period. DTE's own Strategist modeling shows that the capacity factor of the gas plant will decline over time to well below this level, which is what is expected in the long run as utilities in the MISO footprint add more renewable generation with zero variable costs. Even if the R / E portfolio requires a small amount of market purchases to equal the output of the gas plant, this small share of market purchases, plus the fact that natural gas is the marginal fuel in MISO in only about 20% of hours,[45] results in a much more limited exposure to fuel price volatility than the gas plant.

Q: What are the total costs of the R / E portfolio over the 25-year forecast period of 2018-2042?

A: The net present value of the total costs of the R / E portfolio from 2018-2042 is $2.314 billion, with an average cost of $58 per MWh. These costs are summarized in **Table 8**. The table also shows the comparable total costs of the gas plant, which are $2.653 billion, with an average cost of $67 per MWh. Thus, the costs of the proposed R / E portfolio are $339 million (13%) lower than the costs of the gas plant.

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[45] Based on an analysis of the data in the MISO Real-Time Fuel on the Margin Report for calendar year 2015.

Table 8: *Summary of R / E Portfolio Costs vs. Gas Plant (2018-2042)*

Resource	Capacity (MW)		Energy (GWh)		NPV Costs (2018-2042)		
	Nameplate	Accredited	Total GWh	Levelized GWh/year	$MM	$/MWh	$/kW-year
R/E Portfolio:							
Solar	1,100	623	39,630	1,353	$947	$67	
Wind	1,100	139	80,427	2,783	$1,468	$50	
EE @ 2%	94	94	6,436	424	$53	$12	
New DR	261	261			$115		$44
Net Market	(151)	(151)	(11,706)	(771)	($349)	($43)	
Integration			39,737	3,790	$79	$2	
Total	**2,555**	**1,107**	**114,787**	**3,790**	**$2,314**	**$58**	
Gas Plant:							
Total	**1,113**	**1,113**	**114,787**	**3,790**	**$2,653**	**$67**	
Difference: Savings from R/E Portfolio					**$339 MM or 13% NPV**		

Q: Has your R / E portfolio been analyzed using the Strategist model?

A: Yes, it has. Mr. George Evans provides testimony that discusses the results of running Strategist with the key elements of this R / E portfolio, including 2,200 MW of new wind and solar projects and the 2% annual EE savings described above. To be able to make the best comparison possible to DTE's proposed plan, the Strategist model was run using the other input assumptions in DTE's 2016 reference scenario.

Q: What were the results from Strategist when you analyzed your R / E portfolio compared with DTE's 2016 reference case?

A: The results of this run are that a new gas plant is delayed until 2027 and the R / E portfolio generates $1.2 billion (PV) in total cost savings compared to the 2016 DTE reference case with the proposed gas plant operational in mid-2022. The savings from the R / E portfolio in the Strategist model are higher than my more focused analysis, apparently due to (1) the higher gas and market prices in the 2016 reference case, (2) more market sales in the comprehensive Strategist modeling, and (3) a higher revenue requirement for the gas plants used in the Strategist model.

Q: Where does the $1.2 billion in savings come from when comparing the R / E scenario to DTE's 2016 reference case?

A: The savings reflected in the Strategist run come primarily from reduced capital costs and reduced fuel costs. Both are results of avoiding the construction of DTE's proposed combined cycle plant in 2022. Regarding capital costs, because the additional renewable energy and energy efficiency are represented as PPA purchases in Strategist, the model avoids, on average, more than 95% of the annual capital costs between 2018 and 2026. In addition, the Strategist results show an average decline in total fuel costs of 19% and an average decline of 18% in variable O&M costs between 2022 and 2026. Total emissions costs are also reduced by an average of 8% during this period.

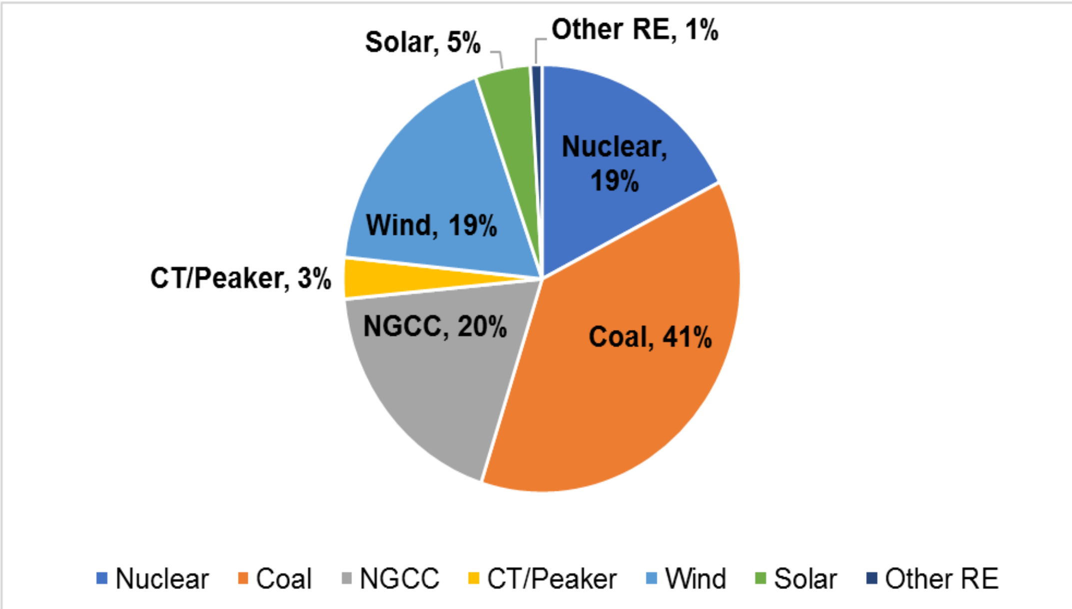
Q: In the R / E scenario, does Strategist choose to build a natural gas-fired combined cycle (NGCC) plant at any point?

A: Yes. Under the R / E scenario, a new NGCC power plant is delayed until 2027. At that point, Strategist chooses to build a 1,531 MW NGCC plant with an additional 150 MW duct burner for a total of 1,681 MW. This new build replaces both NGCC plants in DTE's 2016 reference case – the one proposed in 2022 and the subject of this CON, and the additional one that DTE has stated it intends to build in 2029 as part of its long-term resource plan. This leads to a significant reduction in capital costs throughout the planning period, and, ultimately, significant reductions in the calculated NPV of the R / E scenario compared to DTE's 2016 reference case.

Q: Please describe how DTE's generation portfolio changes under the R / E scenario compared with DTE's 2016 reference case.

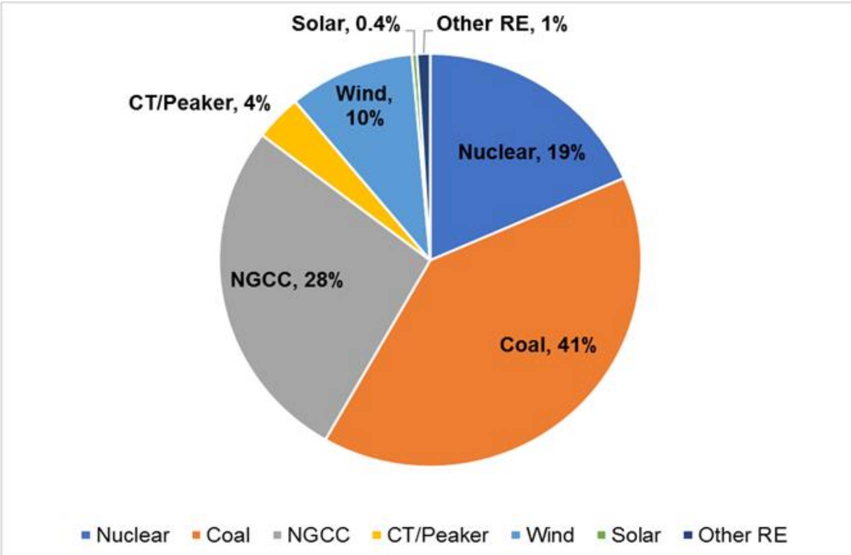
A: Under the R / E portfolio, DTE's generation portfolio is a more diverse, lower risk portfolio than DTE's preferred plan. Under the R / E scenario, renewable energy would be supplying about 25% of DTE's energy by 2030, nuclear would make up about 19%, the NGCC plant added in 2027 would supply approximately 20%, and coal would make up most of the remainder. Even under this scenario, DTE would be more than 64% reliant on fossil fuels for its energy needs. This 2030 resource mix is shown below in **Figure 8**.

Figure 8: 2030 Resource Mix for the R / E Portfolio



However, under DTE's preferred plan, the utility would be even more reliant on fossil fuels, further exacerbating the risks I discuss in my testimony. Under DTE's preferred plan, renewables would make up just over 11% of DTE's energy needs and fossil fuels would be more than 72% of DTE's energy mix. See **Figure 9**. This higher level of reliance on fossil fuels exposes the Company and its ratepayers to even greater risk of fuel price volatility, regulatory costs, and other risks that I detail in my testimony.

Figure 9: 2030 Resource Mix for DTE's Preferred Plan



Q: Please describe how DTE's capacity portfolio changes under the R / E scenario compared with DTE's 2016 reference case.

A: Similar to the increased diversification of DTE's energy portfolio under the R / E scenario compared to the Company's 2016 reference case, the R / E scenario also improves the diversity of capacity resources for the Company. In 2030 under the R / E scenario, DTE's reliance on fossil fuel resources, including coal, the planned NGCC, and DTE's combustion turbine and other peaking plants is just over 64% – 28%, 14%, and 23%, respectively. The bulk of DTE's remaining capacity needs are split relatively evenly amongst nuclear, pumped hydro facilities, and renewables – about 10% each.

By comparison, under DTE's preferred plan, nearly 70% of the Company's capacity needs will be meet with fossil fuels including coal, the planned NGCC units, and DTE's combustion turbine/peaking plants – 28%, 18%, and 24% respectively – in 2030. Renewables would contribute just 3% to DTE's capacity needs, with market purchases filling the remaining gap after nuclear and pumped hydro contribute their respective 10% each.

Q: Why does a more diverse portfolio of energy and capacity resources matter?

A: As discussed above and throughout my testimony, DTE's ongoing overreliance on fossil fuels for its energy and capacity needs injects unnecessary risk into the Company's operations, and ultimately onto its ratepayers. While diversifying the fossil fuel mix with additional natural gas can help to reduce some risk, it inherently injects other types of risks into the mix, such as the risk posed by natural gas price volatility. Incorporating more renewable energy into the Company's mix of energy and capacity resources will reduce these risks.

Q: Did you consider Strategist results for your R / E portfolio using the revised assumptions in the 2017 reference case?

A: No, I did not. My review of the Strategist outputs for DTE's own run of the 2017 reference case revealed several unrealistic and apparently erroneous assumptions in the 2017 reference case. Most important, the advanced combined cycles selected in 2022-2023 and 2029 in DTE's own run using the 2017 reference case have average heat rates of just 5,300 Btu per kWh and 5,600 Btu per kWh, respectively, which clearly are not realistic. In comparison, the gas plant selected in 2022-2023 in DTE's 2016 reference case run has an average heat rate of about 6,500 Btu per kWh, which is appropriate for the advanced combined cycle unit that DTE proposes to build. In addition, the 2017 reference case shows the existing Belle River peaker (BLRPKR) with a heat rate of just 5,800 – 5,900 Btu per kWh, when that unit's actual heat rate is 12,000 Btu per kWh. Given these apparent significant errors in the assumptions for the Strategist modeling using the 2017 reference case, I have not considered results using that case. My analysis comparing the R / E portfolio and the gas plant does use certain important elements of the 2017 reference scenario, including the forecasts of natural gas and MISO market prices.

3. Cost Sensitivities

Q: Have you examined sensitivity cases that change key drivers of the costs of the R / E portfolio?

A: Yes. **Table 9** lists the key base case assumptions as well as the sensitivities for these assumptions that I examined. The sensitivity cases labeled "low" <u>reduce</u> the cost difference between the gas plant and the R / E portfolio; the cases labeled "high" <u>increase</u> the savings from the R / E portfolio compared to the gas plant.

Table 9: *Base Case Assumptions and Sensitivity Cases*

Assumption	Base Case	Sensitivity Cases	
		Low	**High**
Natural gas price	DTE Forecast	6 years of forwards & PACE escalation	2 years of forwards & PACE escalation
Solar trade case	Tariff imposed		No tariff
Wind capacity value	Zone 7 (12.6%)		MISO-wide (15.6%)
Early coal retirements?	No	1 year early	
EE assumptions	DTE 2.0%/yr	DTE 1.5%/yr	
Gas plant capacity factor	Strategist output	Fixed at 71%	

Q: How do these sensitivities impact the cost difference between the gas plant and your R / E portfolio?

A: **Table 10** shows the cost difference between the gas plant and the R / E portfolio for each of the Low and High sensitivities listed in Table 9. The differences are expressed in terms of both (1) the difference in the net present value of the revenue requirement (NPVRR) in millions of dollars and (2) the difference as a percentage of the gas plant's costs.

Table 10: *Results of Sensitivity Cases – R / E Portfolio Savings vs. DTE Gas Plant*

Assumption	Low		High	
	NPVRR (*MM $*)	%	NPVRR (*MM $*)	%
Natural gas price	$25	1%	$408	15%
Solar trade case			$359	14%
Wind capacity value			$350	13%
Retire coal 1-year early	$308	12%		
Retire coal 2-years early	$274	10%		
EE assumptions - 1.5%/yr	$182	7%		
Constant gas plant output	$87	3%		

4. Procuring the R / E portfolio

Q: The R / E portfolio that you have proposed includes the procurement of 2,200 MW of new wind and solar resources. How would DTE procure this significant amount of new renewables?

A: There are multiple ways in which these new renewable resources can be procured, as discussed below.

PURPA Contracts. Michigan utilities may see significant renewable development in the state under the new PURPA avoided cost pricing methodology that the Commission has adopted, as exemplified in the Commission's recent order for Consumers Energy.[46] The new pricing is based on the assumption that avoided energy and capacity costs should be based on the energy- and capacity-related costs of a new combined-cycle unit. Thus, if this approach is implemented accurately, and if wind and solar resources are less expensive than a new combined-cycle unit (as my analysis of the R / E portfolio suggests is likely), then DTE's service territory may see significant development of new renewable resources under long-term PURPA contracts. States such as Idaho, North Carolina, and Utah have seen substantial development of solar QFs when they have made

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[46] On May 31, 2017, the Commission issued an order in Case No. U-18090 finding that the most appropriate method for determining Consumers' avoided capacity and energy costs is the Staff's hybrid-proxy method, which is based on the avoided capacity cost of a gas-fired combustion turbine (NGCT) and the avoided energy cost of a combined-cycle unit, plus assigning a portion of combined-cycle investment costs to the energy rate.

long-term PURPA contracts available under avoided cost contracts that are based largely on marginal generation costs from natural gas-fired resources.

Long-term contracts from Renewable RFPs. DTE also could procure new renewable resources through a Commission-authorized procurement process based on competitive requests for proposals (RFPs). Utilities in many states have used competitive RFPs to meet requirements to procure new renewable resources to comply with the Renewable Portfolio Standards (RPS).

Utility-owned generation. DTE owns a portion of its wind resources and both of its existing utility-scale solar facilities. DTE could develop and own a portion of the new renewable resources in the proposed R / E portfolio, assuming that it can show that utility ownership is less expensive than contracting with third party developers for these new resources.

Customer-sited DG. New renewable generation, particularly distributed solar, can be installed at a wide range of scales on customers' premises under Michigan's net metering program. The higher costs of smaller-scale solar DG installations can be offset by the added benefits of savings in the utility's "wires" costs for line losses and for transmission and distribution upgrades. The widespread adoption of solar DG also could require increases in or the removal of Michigan's existing cap on the capacity of net-metered, customer-sited facilities.

Community solar and **green pricing** programs are used in a number of states to increase access to incremental solar and wind generation by utility customers of all sizes.

V. THE R / E PORTFOLIO PROVIDES SIGNIFICANT ADDITIONAL NET BENEFITS

A. Employment Benefits

Q: Will the R / E portfolio generate more new jobs in southeast Michigan than the proposed gas plant?

A: Yes. The testimony of Mr. Philip Jordan of BW Research Partnership (BW Research) discusses the added jobs and general economic impacts of the capacity and energy that would result from the R / E portfolio proposed in this testimony. This includes the short-term construction jobs associated with the wind and solar capacity additions, the longer-term employment operating and maintaining this capacity over time, and the industry jobs associated with the incremental energy efficiency programs. BW Research found that the portfolio of wind, solar, and energy efficiency would create 5,779 direct jobs, of which 5,642 are construction/installation jobs and 137 are ongoing operating and maintenance jobs. In addition, the economic activity created by the R / E portfolio would create another 2,582 indirect jobs in the supply chain, and 7,998 induced jobs in the broader economy. Mr. Jordan's testimony discusses in detail the methodology that BW Research used to perform this analysis.

In comparison, DTE's testimony asserts that the gas plant will add, at the peak of construction, 580 full-time-equivalent jobs.[47] The ongoing, long-term jobs required to operate the plant will be 35 employees.[48]

B. Reduced Air Emissions of Carbon and Criteria Pollutants

Q: Will the R / E portfolio have reduced air emissions of criteria air pollutants (NO_x, SO_2, and particulates) and carbon dioxide (CO_2), compared to the gas plant?

A: Yes. DTE's testimony provides the gas plant's expected air emissions.[49] The only emissions associated with the R / E portfolio are those that would result if net purchases from the MISO market are needed to balance the R / E portfolio's output to equal the production of the gas plant. My base case modeling of the gas plant suggests that the R / E Portfolio will result in about 771 GWh/year of additional energy production compared to the gas plant. This renewable energy can be sold into the MISO market, reducing emissions. To calculate these incremental emission reductions, I used MISO's reported hourly data on the marginal fuel in its markets. There also may be significant incremental emission reductions achievable if the retirement dates of coal units scheduled to close

[47] DTE Testimony of I.M. Dimitry, at pp. IMD-31 and D. O. Fahrer at pp. DOF-13.
[48] DTE Testimony of I.M. Dimitry, at pp. IMD-31 to IMD-32.
[49] DTE Testimony of B.J. Marietta, at p. BJM-13 and Exhibit A-36.

before 2023 are moved forward in time. **Table 11** shows the assumed marginal air emissions from the gas plant, the MISO market, and the retiring coal plants. Note that the marginal emissions from the market are higher than from the gas plant.

Table 11: *Marginal Air Emissions*

Resource	**CO_2** *(tons/Mwh)*	**SO_2** *(lbs/MWh)*	**NOx** *(lbs/MWh)*	**$PM_{2.5}$** *(lbs/MWh)*
Proposed Gas Plant	0.381	0.004	0.024	0.013
MISO Market	0.589	4.701	1.222	0.037
Retiring Coal Plants	1.284	11.721	3.036	0.092

Q: What are the benefits of reducing criteria air pollutants?

A: Reductions in criteria pollutant emissions improve human health. Exposure to particulate matter (PM) causes asthma and other respiratory illnesses, cancer, and premature death.[50] Nitrous oxides (NO_X) react with volatile organic compounds in the atmosphere to form ozone, which causes similar health problems.[51] For quantifying the health benefits, I use the health co-benefits from reductions in criteria pollutants that the EPA has developed, discussed below.[52] My analysis assumes a real societal discount rate of 3%, which is a typical societal discount rate often used in long-term benefit/cost analyses.

50 EPA, *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants* (June 2014), p. 4-14 and Table 4-6 ("*CPP Impact Analysis*"). Available at http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf.

51 *Ibid.*

52 For example, in 2014 EPA summarized its work on the health benefits of reductions in criteria pollutant emissions as part of the technical analysis for the Clean Power Plan. Additional reductions in emissions of criteria pollutants would have been an accompanying benefit of the Clean Power Plan.

SO_2. The EPA has calculated the health-related costs of SO_2 emissions for 2020, 2025, and 2030.[53] Values for intermediate years are interpolated between the five-year values. I assume that generators must purchase SO_2 emission allowances at market prices; thus, the societal value of reduced air emissions should be net of the market cost of required allowances. The market value of SO_2 can be taken from the EPA's 2017 SO_2 allowance auctions. However, the final clearing price of the latest spot auction was just $0.04 per ton.[54] This is low enough compared to the social cost that it is negligible for my calculations.

NOx. Heath damages from exposure to nitrous oxides come from the compound's role in creating secondary pollutants: nitrous oxides react with volatile organic compounds to form ozone, and are also precursors to the formation of particulate matter.[55] EPA has calculated the health benefits of reductions in NOx emissions in 2020, 2025, and 2030.[56] The compliance market for NO_x in Michigan is governed by the EPA's Cross State Pollution Rule. I assume a recent value of $750 per ton for NOx

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53 The total social cost of SO_2 is taken from *CPP Impact Analysis*, at Tables 4-7, 4-8, and 4-9.
54 EPA 2017 SO2 Allowance Auction. Found at: https://www.epa.gov/airmarkets/2017-so2-allowance-auction-0.
55 *CPP Impact Analysis*, p. 4-14 and Table 4-6.
56 *Ibid.*, at Tables 4-7, 4-8, and 4-9.

compliance costs, and subtract this cost from the health benefits to determine the net benefits.[57]

Fine Particulates ($PM_{2.5}$). I use the damage costs for $PM_{2.5}$, because $PM_{2.5}$ are the small particulates with the most adverse impacts on health. The EPA health co-benefit figures distinguish between types of particulate matter, and calculate two separate benefit-per-ton estimates for PM: for PM emitted as elemental and organic carbon, and for PM emitted as crustal particulate matter.[58] The EPA estimates that approximately 85% of primary $PM_{2.5}$ emitted in Michigan is crustal material, with the bulk of the remainder being elemental or organic carbon.[59] The emissions factors for total primary $PM_{2.5}$ do not differentiate among particle types.[60] As a result, I weigh the mid-point of each of the two benefit-per-ton estimates according to EPA's assumptions for Michigan emissions.

Q: How have you valued the benefit of reducing carbon dioxide emissions?

A: Yes. I first calculated the direct ratepayer benefits from the potential reduced costs of compliance with future carbon regulations, based on the carbon prices that DTE projected in several of its IRP scenarios. Then I estimated the societal benefits of lower carbon

[57] See the EPA Cross State Air Pollution Rule. Found at: https://www.epa.gov/csapr. Recent NOx emission allowance prices can be found at http://www.evomarkets.com/content/news/reports_23_report_file.pdf.

[58] *CPP Impact Analysis*, p. 4-26, Tables 4-7, 4-8, and 4-9.

[59] *Ibid*., p. 4A-8, Figure 4A-5.

[60] AP 42, Table 1.4-2, Footnote (c).

emissions, based on mitigating the damages from climate change. For this calculation I used the **social cost of carbon** (SCC) net of the assumed carbon compliance costs.

The SCC is "a measure of the seriousness of climate change."[61] It is a way of quantifying the value of actions to reduce greenhouse gas emissions, by estimating the potential damages if carbon emissions are not reduced. The anticipated costs to comply with future regulation of carbon emissions may well be lower than the true costs that carbon pollution imposes on society, which are the damages estimated by the SCC. As a result, the additional costs in the SCC, above the compliance costs of mitigating carbon emissions, represent the societal benefits of avoided carbon emissions.

The most prominent and well-developed source for estimates of the social cost of carbon is the federal government's Interagency Working Group on the Social Cost of Carbon.[62] These values have been vetted by numerous government agencies, research institutes, and other stakeholders. The cost values were derived by combining results from the three most prominent integrated assessment models, each run under five different reference

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[61] Anthoff, D. and Toll, R.S.J. 2013. The uncertainty about the social cost of carbon: a decomposition analysis using FUND. *Climactic Change* 117: 515-530.

[62] Interagency Working Group on Social Cost of Carbon, *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866* (May 2013, Revised July 2015). Available at: https://www3.epa.gov/climatechange/Downloads/EPAactivities/social-cost-carbon.pdf.

scenarios.[63] The group gave equal weight to each model and averaged the results across each scenario to obtain a range of values depending on the discount rate, given in the table below.

Table 12: *Social Cost of Carbon*[64] *(2007 $ per metric tonne of CO_2)*

	Discount Rate		
	5%	**3%**	**2.5%**
Social Cost of Carbon	11	36	56

I have assumed a value for the SCC using the mid-range value of $36 per metric tonne based on a 3% real discount rate. I escalate these benefits by 5% per year, recognizing that "future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climate change."[65]

While estimating the social cost of carbon contains many inherent uncertainties, I believe these values are appropriate. As noted above, the mid-range real discount rate of 3% is often used in long-term benefit/cost analyses. It is also a conservative assumption, when considering the diminished prosperity future generations will face in a world heavily impacted by climate disruption. Because "the choices we make today greatly influence

63 *Id.* The three models are the Dynamic Integrated Climate-Economy (DICE) model, the Climate Framework for Uncertainty, Negotiation and Distribution (FUND) model, and the Policy Analysis of the Greenhouse Effect (PAGE) model.

64 *Id.*, p. 13.

65 *Id*, pp. 13-14. 5% annual escalation in carbon costs has been used in both California and Arizona. See the CPUC Final Public Tool referenced in Footnote 2, at tab "Key Driver Inputs," at Cell D33. 5% is also midway between the two escalation rates (2.5% and 7.5% per year) used in the carbon cost scenarios in Arizona Public Service's *2014 Integrated Resource Plan*.

the climate our children and grandchildren inherit," future benefits should not be significantly discounted relative to current costs.[66] As Pope Francis wrote in his encyclical calling for "all people of goodwill" to take action on climate change: "The climate is a common good, belonging to all and meant for all."[67]

Reduced methane leakage. Methane leakage in the natural gas infrastructure that serves the gas plant also will be a significant source of carbon emissions. I attach to this report as **Ex. ELP-62 (RTB-5)** a recent white paper calculating the additional greenhouse gas emissions associated with methane leaked in providing the fuel to gas-fired power plants. This issue has received significant attention recently as a result of the major methane leak from the Aliso Canyon gas storage field in southern California. The bottom line is that the CO_2 emission factors of gas-fired power plants should be increased by 50% to account for these directly-related methane emissions from the production and pipeline infrastructure that serves gas-fired electric generation. I do not quantify this additional benefit of the R / E portfolio, but it is a reason why the benefits from reduced carbon emissions that I do quantify should be viewed as conservative.

[66] California Climate Change Center, Our Changing Climate: Assessing the Risks to California (2006) at p. 2. http://www.energy.ca.gov/2006publications/CEC-500-2006-077/CEC-500-2006-077.pdf.

[67] Encyclical Letter *Laudato Si'* of the Holy Father Francis on Care for Our Common Home. June 18, 2015.

Q: What are the air emission benefits from the R / E portfolio, compared to the gas plant?

A: The first set of benefits from the R/E portfolio compared to the gas plant are the reduction in direct ratepayer costs for complying with emissions regulations for NOx and carbon. These are $13 million per year. The annual societal air emission benefits, net of the compliance benefits, are $367 million per year over the 2018-2042 period, as shown in the first three rows of **Table 13** below.

Q: Would there also be air emission benefits from the early retirement of River Rouge, St. Clair, and Trenton Channel coal units?

A: Yes. The air emission benefits of a one-year acceleration of the retirement of these three coal units are very large, as shown in the bottom line of **Table 13** below, as a result of the high value of reducing SO_2 emissions.[68]

Table 13: *Annual Societal Benefits / (Costs) from Air Emission Reductions / (Increases) (NPV 2018-2042, millions of $ per year)*

Resource	CO_2	SO_2	NOx	$PM_{2.5}$	Total
Proposed Gas Plant	(174)	(1)	(1)	(2)	(177)
R / E Portfolio	32	150	7	1	190
Net Benefit of R / E					367
Retiring Coal Plants *(one year advance in retirement)*	501	3,409	150	25	4,084

[68] Air emissions from the retiring coal plants and from the gas plant are from DTE Testimony of B.J. Marietta, at p. BJM-13.

C. Reliability and Resiliency

Q: Does the proposed R / E portfolio offer greater reliability and resiliency benefits that a single central station gas plant?

A: Yes. Utility-scale wind and solar projects typically are installed in greater numbers and with smaller average project capacities than central-station fossil units. Renewable DG obviously consists of hundreds or thousands of small, widely distributed systems. As a result of their smaller size, wide geographic dispersion, and different prime movers, renewable resources are highly unlikely to experience outages at the same time. As a simple example, a single 1,000 MW gas plant with a 5% forced outage rate will have a 5% chance that the entire 1,000 MW of capacity will be unavailable during a peak demand hour. A portfolio of 2,000 MW of solar capacity that provides 1,000 MW of firm capacity equivalent to the gas plant might consist of forty 50 MW units that are widely dispersed. If each solar unit also has a 5% forced outage rate, the chance that the entire 2,000 MW of solar capacity will be unavailable in a peak demand hour is much less than 5%, and indeed is vanishingly small. Thus, the impact of any individual outage at a solar unit will be far less consequential than an outage at a major central station power plant.[69] In addition, if the renewable resource is owned by a third-party developer

[69] One study of the benefits of solar DG has estimated the reliability benefits of DG from a national perspective. The study assumed that a solar DG penetration of 15% would reduce loadings on the grid during peak periods, mitigating the 5% of outages that result from such high-stress conditions. Based on a study which calculated that power outages cost the U.S. economy about $100 billion per year in lost economic output, the levelized, long-term benefits of this risk reduction were calculated to be $20 per MWh ($0.02 per kWh) of DG output. This calculation does not necessarily assume that the DG is located behind the customer's meter, so this reliability benefit also might result from widely distributed DG at the

or by a customer, it is the developer or DG customer, and not ratepayers, who will bear this operating risk and will pay for the repairs.

However, most electric system interruptions do not result from generation outages or high demand on the system, but from weather-related transmission and distribution system outages. Renewable DG is located at or near the point of end use, and thus also reduces the risk of outages due to transmission or distribution system failures. In these more frequent events, renewable DG paired with on-site storage can provide customers with an assured back-up supply of electricity for critical applications should the grid suffer an outage of any kind. This benefit of enhanced reliability and resiliency has broad societal benefits as a result of the increased ability to maintain government, institutional, and economic functions related to safety and human welfare during grid outages.

Both DG and storage are essential in order to provide the reliability enhancements that are needed to eliminate or substantially reduce weather-related interruptions in electric service. The DG unit ensures that the storage is full or can be re-filled promptly in the absence of grid power, and the storage provides the alternative source of power when the grid goes down. DG also can supply some or all of the on-site generation necessary to develop a micro-grid that can operate independently of the broader electric system. It is challenging to quantify this benefit, which will be realized over time as storage

wholesale level. Hoff, Norris and Perez, *The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania* (November 2012), at Table ES-2 and pages 18-19.

technology is added to renewable DG systems.[70] Nonetheless, solar DG is a foundational element necessary to realize this benefit – in much the same way that smart meters are necessary infrastructure to realize the benefits of time-of-use rates, dynamic pricing, and demand response programs that will be developed in the future – and thus the reliability and resiliency benefits of wider renewable deployment should be recognized as a broad societal benefit in comparison to central station generation.

D. Integration Costs Will Be Nominal

Q: The R / E portfolio will result in a higher penetration of solar and wind resources in Michigan. Please comment on whether this increasing penetration of renewables is likely to result in additional costs to integrate these new resources.

A: The addition of significant intermittent wind and solar resources may increase the variability of the "net load" – defined as the end use load less wind and solar resources – that the utility must serve with dispatchable generation. This increased variability that intermittent wind and solar output adds to the utility system can require additional ancillary services, such as regulation. A number of utilities have performed detailed studies of such integration costs, including studies that cover a wide range of renewable penetrations. Xcel Energy in Colorado calculated solar integration costs as $1.80 per

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[70] It is also important to recognize that adding storage may be cost-effective even without considering its reliability benefits when paired with DG. Distributed storage can reduce demand charges, allow TOU rate arbitrage, and provide power quality and capacity-related benefits to the utility or grid operator. Indeed, distributed storage may be economic as a result of the benefits in these other use cases, without considering the reliability benefits for the customer.

MWh on a 20-year levelized basis.[71] A March 2014 study by Duke Energy estimated solar integration costs on its system in North Carolina ranging from $1.43 to $9.82 per MWh, depending on the level of PV penetration.[72] Based on the solar penetration level in Michigan, the lower end of the range in the Duke study would apply. Arizona Public Service did a 2012 integration study that estimated integration costs on its system of $2 per MWh in 2020.[73] Based on this body of work, $2 per MWh represents a reasonable assumption for a 25-year levelized solar integration cost in DTE's service territory, and this cost has been included as a cost of the R / E portfolio, as shown in Table 8 above. In its application, DTE did not assume any incremental integration costs in its scenarios with higher amounts of renewables.[74]

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71 Xcel Energy Services for Public Service Company of Colorado, "Cost and Benefit Study of Distributed Solar Generation on the Public Service Company of Colorado System" (May 23, 2013), at Table 1, pages v and 41-42. Available at http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs%20and%20Benefits%20of%20Distributed%20Solar%20Generation%20on%20the%20Public%20Service%20Company%20of%20Colorado%20System%20Xcel%20Energy.pdf

72 See http://www.pnucc.org/sites/default/files/Duke%20Energy%20PV%20Integration%20Study%20201404.pdf

73 See Arizona Public Service, *2014 Integrated Resource Plan*, at p. 43, citing Black & Veatch, "Solar Photovoltaic (PV) Integration Cost Study" (B&V Project No. 174880, November 2012).

74 DTE response to ELPCDE 3.1f and 3.3a/b, included in Exhibit RTB-2.

VI. CONCLUSION

Q: Can you please summarize your conclusions?

A: DTE's IRP process was incomplete and flawed. As a result, the Proposed Project is not the most reasonable and prudent means for DTE to meet its customers' needs. DTE's failing is exemplified by my evaluation of a portfolio of renewables and efficiency resources that could provide the same capacity and energy as the gas plant, with appreciably lower costs and risks to DTE's ratepayers. There are no negative impacts from this alternative scenario, and this clean course of action will provide much greater employment benefits to southeast Michigan than the gas plant, will reduce harmful air emissions, and will enhance the reliability of the electric system.

Q: Does this conclude your direct testimony in this case?

A: Yes, it does.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

EXHIBITS OF

R. THOMAS BEACH

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the U.S., and Canada.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

- *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

- *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

- *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** (R. 04-08-018 – February 21, 2006)

- *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

- *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

- *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

- *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

- *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

- *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

- *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

- *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

- *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

- *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

- *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

- *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

85. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 15-04-012—July 5, 2016)

    - *Selection of Time-of-Use periods, and rate design issues for solar customers.*

EXPERT WITNESS TESTIMONY BEFORE THE ARIZONA CORPORATION COMMISSION

1. Prepared Direct, Rebuttal, and Supplemental Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. E-00000J-14-0023, February 27, April 7, and June 22, 2016).

   - *Development of a benefit-cost methodology for distributed, net metered solar resources in Arizona.*

2. Prepared Surrebuttal and Responsive Testimony of R. Thomas Beach on behalf of the **Energy Freedom Coalition of America** (Docket No. E-01933A-15-0239 – March 10 and September 15, 2016).

   - *Critique of a utility-owned solar program; comments on a fixed rate credit to replace net energy metering.*

EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **Colorado Solar Energy Industries Association** and the **Solar Alliance**, (Docket No. 09AL-299E – October 2, 2009). https://www.dora.state.co.us/pls/efi/DDMS_Public.Display_Document?p_section=PUC&p_source=EFI_PRIVATE&p_doc_id=3470190&p_doc_key=0CD8F7FCDB673F1043928849D9D8CAB1&p_handle_not_found=Y

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **Vote Solar Initiative** and the **Interstate Renewable Energy Council**, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

3. Answer Testimony and Exhibits, plus Opening Testimony on Settlement, of R. Thomas Beach on behalf of the **Solar Energy Industries Association**, (Docket No. 16AL-0048E [Phase II] – June 6 and September 2, 2016).

   - *Rate design issues related to residential customers and solar distributed generation in a Public Service of Colorado general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of **Georgia Interfaith Power & Light and Southface Energy Institute, Inc.** (Docket No. 40161 – May 3, 2016).

   - *Development of a cost-effectiveness methodology for solar resources in Georgia.*

EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

1. Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **Northeast Clean Energy Council, Inc.** (Docket D.P.U. 15-155, March 18 and April 28, 2016)

   - *Residential rate design and access fee proposals related to distributed generation in a National Grid general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of **Geronimo Energy, LLC**. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

EXPERT WITNESS TESTIMONY BEFORE THE MONTANA PUBLIC SERVICE COMMISSION

1. Pre-filed Direct and Supplemental Testimony of R. Thomas Beach on Behalf of **Vote Solar and the Montana Environmental Information Center** (Docket No. D2016.5.39, October 14 and November 9, 2016).

   - *Avoided cost pricing issues for solar QFs in Montana.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

    - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

    - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

    - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

4. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket Nos. 15-07041 and 15-07042 –October 27, 2015).
   b. Prepared Direct Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 1, 2016).
   c. Prepared Rebuttal Testimony of R. Thomas Beach on Grandfathering Issues on behalf of **TASC**, (Docket Nos. 15-07041 and 15-07042 –February 5, 2016).

    - *Net energy metering and rate design issues in Nevada.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

1. Prepared Direct and Rebuttal Testimony of R. Thomas Beach on behalf of **The Alliance for Solar Choice (TASC)**, (Docket No. DE 16-576, October 24 and December 21, 2016).

    - *Net energy metering and rate design issues in New Hampshire.*

EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)
   http://164.64.85.108/infodocs/2011/3/PRS20156810DOC.PDF

    - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

April 25, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=89f3b50f-17cb-4218-87bd-c743e1238bc1
May 30, 2014:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=19e0b58d-a7f6-4d0d-9f4a-08260e561443
June 20, 2104:
http://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=bd549755-d1b8-4c9b-b4a1-fc6e0bd2f9a2

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014) https://dms.psc.sc.gov/attachments/matter/B7BACF7A-155D-141F-236BC437749BEF85

    - *Methodology for evaluating the cost-effectiveness of net energy metering*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF TEXAS

1. Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (SEIA) (Docket No. 44941 – December 11, 2015)

    - *Rate design issues concerning net metering and renewable distributed generation in an El Paso Electric general rate case.*

EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

    - *Issues concerning the term of PURPA contracts in Idaho.*

EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

    - *Avoided cost pricing issues in Vermont*

EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION

Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011) http://www.scc.virginia.gov/docketsearch/DOCS/2gx%2501!.PDF

- *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

MPSC Case No.:	U-18419
Respondent:	D. Swiech
Requestor:	ELPC
Question No.:	ELPCDE-1.36
Page:	1 of 1

Question: Is the increase in DTE's NEXUS capacity from 30,000 per day to 75,000 per day contingent on the construction of the proposed CCGT Project?

Answer: The NEXUS agreement allows DTE Electric to elect to increase its capacity from 30,000 Dth/d to 75,000 Dth/d on the in-service date of a CCGT facility with at least 680 MW capacity and at least 70% capacity factor. The Proposed Project meets these criteria.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-1.37
Page: 1 of 1

Question: Please provide the expected transportation rate for DTE's intended capacity on the NEXUS pipeline.

Answer: The expected transportation rate for DTE Electric's capacity on NEXUS is \$0.695/Dth plus 1.32% fuel.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-1.41a
Page: 1 of 1

Question: Please explain how DTE intends to structure gas supply contracts to "minimize price volatility" (page DS-8).

a. Will DTE sign long-term, fixed price gas supply contracts? If not, what other means will DTE use to minimize price volatility?

Answer: The Company will consider long-term, fixed price gas supply contracts.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-1.41b
Page: 1 of 1

Question: Please explain how DTE intends to structure gas supply contracts to "minimize price volatility" (page DS-8).

b. If DTE does plan to sign fixed-price gas supply contracts, does DTE assume that these contracts will include a price premium over market prices in order to provide price certainty? If so, what is that premium?

Answer: The Company has not made that assumption.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-1.41c
Page: 1 of 1

Question: Please explain how DTE intends to structure gas supply contracts to "minimize price volatility" (page DS-8).

c. If DTE will use means other than fixed-price gas supply contracts to minimize price volatility, what is the expected annual cost of these means?

Answer: Utilizing natural gas storage services can also lessen the impact of price volatility. The benefits or cost of utilizing storage to minimize price volatility have not been determined.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-1.41d
Page: 1 of 1

Question: Please explain how DTE intends to structure gas supply contracts to "minimize price volatility" (page DS-8).

d. What is the expected term of the "forward gas supply" contracts that DTE will procure (see p. DS-8)?

Answer: The term of forward gas supply contracts has not been decided.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-1.42a
Page: 1 of 1

Question: Please explain whether DTE currently uses "forward gas supply" contracts to serve its existing natural gas requirements.

a. If it does, please provide the volume and terms of these contracts, and explain the basis for the pricing used in these agreements.

Answer: Yes, DTE Electric currently utilizes forward gas supply contracts to serve a portion of its existing natural gas requirements.

A gas supply contract is in place through May 31, 2018, for Renaissance that allows DTE Electric to purchase up to 170,554 Dth of gas per day based on MichCon Citygate daily index prices or market fixed prices.

A gas supply contract is in place through October 31, 2018, for Dean that allows DTE Electric to purchase up to 94,152 Dth of gas per day based on MichCon Citygate daily index prices or market fixed prices.

A gas supply contract is in place through April 30, 2020, for Greenwood and the Greenwood peakers that allows DTE Electric to purchase up to 260,000 Dth of gas per day based on Dawn daily index prices or market fixed prices.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-1.42b
Page: 1 of 1

Question: Please explain whether DTE currently uses “forward gas supply” contracts to serve its existing natural gas requirements.

b. Do these contracts have fixed prices for their term?

Answer: No, these contracts do not have fixed prices.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-2.4b
Page: 1 of 1

Question: Regarding Mr. Sweich's forecast of monthly natural gas prices from June 2022 to December 2040:

b. Is the "BRGAS Adder" based on a Chicago Mercantile Exchange (CME) basis differential or is it based on the difference between CME MichCon (or Dawn hub) vs. CME Henry Hub forward strip prices for a particular trade date(s)?

Answer: The "BRGAS Adder" is based on the difference between the CME MichCon forward prices plus $0.10/Dth and the CME Henry Hub forward prices in 2022. The trade date utilized was May 10, 2017. The "BRGAS Adder" was then escalated annually through 2040 using the 2017 deflator series as found in work paper KJC-374, tab deflator series.

MPSC Case No.:	U-18419
Respondent:	D. Swiech
Requestor:	ELPC
Question No.:	ELPCDE-2.4h
Page:	1 of 1

Question: Regarding Mr. Sweich's forecast of monthly natural gas prices from June 2022 to December 2040:

h. Did Mr. Sweitch's gas price forecast make use of any of the PACE fundamentals forecasts that are included in Mr. Chreston's workpapers?

Answer: Yes. The Henry Hub forecast in column C of workpaper DS-1 for years 2025 – 2040 utilizes the PACE fundamentals forecast.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-3.3a
Page: 1 of 1

Question: Refer to page 10 of Witness Chreston's testimony, where he states that "[w]hile wind and solar compare favorably relative to environmental sustainability aspects, the fact that they are not dispatchable to meet load needs requires integration with the other resources in the portfolio to maintain system reliability."

a. Please explain what was done in the IRP process to support the statement that "wind and solar requires integration?"

Answer: In the IRP modeling, wind and solar units were modeled as a transaction with an hourly shape based on historical data.

The dispatch models (Strategist and PROMOD) then dispatch the other dispatchable units, buy and sell from the MISO market to serve the company's need on an hourly basis. The resulting market value of the renewables based on their hourly shapes are thus accounted for in the modeling economic results in this way. This is how the company accounted for the fact that wind and solar are not dispatchable in the IRP models. No other explicit adders for ancillary services or integration of wind and solar were used in the IRP to maintain an optimistic view of renewables value.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-3.3b
Page: 1 of 1

Question: Refer to page 10 of Witness Chreston's testimony, where he states that "[w]hile wind and solar compare favorably relative to environmental sustainability aspects, the fact that they are not dispatchable to meet load needs requires integration with the other resources in the portfolio to maintain system reliability."

b. Please provide supporting calculations for any quantitative values applied for the "wind and solar required integration."

Answer: Please refer to ELPCDE-3.3a. There were no quantitative values applied for integration of wind and solar in the IRP modeling to maintain an optimistic view.

MPSC Case No.: U-18419
Respondent: K. J. Chreston
Requestor: ELPC
Question No.: ELPCDE-3.8
Page: 1 of 1

Question: Please provide a version of Exhibit A-9 (all pages), the Proposed Project Revenue Requirement (based on 2017 Reference) from 2016-2040, without also including the second combined-cycle gas plant that DTE would like to build in 2029. In other words, please provide the annual Project Revenue Requirement only for the 1,100 MW gas plant that DTE proposes to bring on-line in 2023 and for which DTE requests a CON in this case.

Page 5 of 5 of the current Exhibit A-9 appears to show the annual revenue requirements for both the 2023 and 2029 combined-cycle plants; Vote Solar would like to see just the annual revenue requirements from 2016-2040 for the 2023 combined cycle that is the subject of this case.

Please also show the net PSCR impacts just for the 2023 plant.

Answer: A version of Exhibit A-9 without the second combined cycle in 2029 does not exist.

MPSC Case No.: U-18419
Respondent: M. E. Banks/Legal
Requestor: ELPC
Question No.: ELPCDE-3.11a Revised
Page: 1 of 1

Question: Please provide the recent Generating Availability Data Systems (GADS) publication that covers reported years 2011 to 2015 which shows that "operating large frame combined cycle generating stations have a typical availability of over 87% percent," as stated by Mr. Damon on page WHD-15.

a. Please explain whether or not this data includes availability data on the advanced class of frame turbines that DTE proposes to use in this project.

Answer: DTE Electric objects for the reason that the information requested consists of confidential, proprietary research and development of trade secrets or commercial information, the disclosure of which would cause DTE Electric and its customers competitive harm. Subject to this objection and without waiver thereof, the Company would answer as follows:

The publication does not include availability on the advanced class of frame turbines that DTE Electric proposes to use in this project

MPSC Case No.: U-18419
Respondent: M. E. Banks
Requestor: ELPC
Question No.: ELPCDE-3.11b
Page: 1 of 1

Question: Please provide the recent Generating Availability Data Systems (GADS) publication that covers reported years 2011 to 2015 which shows that "operating large frame combined cycle generating stations have a typical availability of over 87% percent," as stated by Mr. Damon on page WHD-15.

a. Please provide any more recent GADS publications, or other industry publications, with data on the achieved availability in actual operations of the advanced class of frame turbines that DTE proposes to use in this project.

Answer: There is no updated GADS information available regarding the achieved availability in actual operations of the advanced class of frame DTE has proposed to use.

MPSC Case No.: U-18419
Respondent: D. Swiech
Requestor: ELPC
Question No.: ELPCDE-7.14
Page: 1 of 1

Question: Is DTE requesting Commission approval in this proceeding for its recovery of the costs of its subscription for up to 75,000 Dth per day of capacity on the NEXUS pipeline? If it is not, where and when does DTE expected to request cost recovery for the NEXUS capacity?

Answer: No. The Company expects to begin incurring costs related to the NEXUS capacity in 2018. Therefore, in September 2017, the Company filed its 2018 PSCR Plan (Case No. U-18403), which requested Commission review and approval of the expense associated with DTE Electric’s agreements with NEXUS.

AEG
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.

This work was performed by

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EXECUTIVE SUMMARY

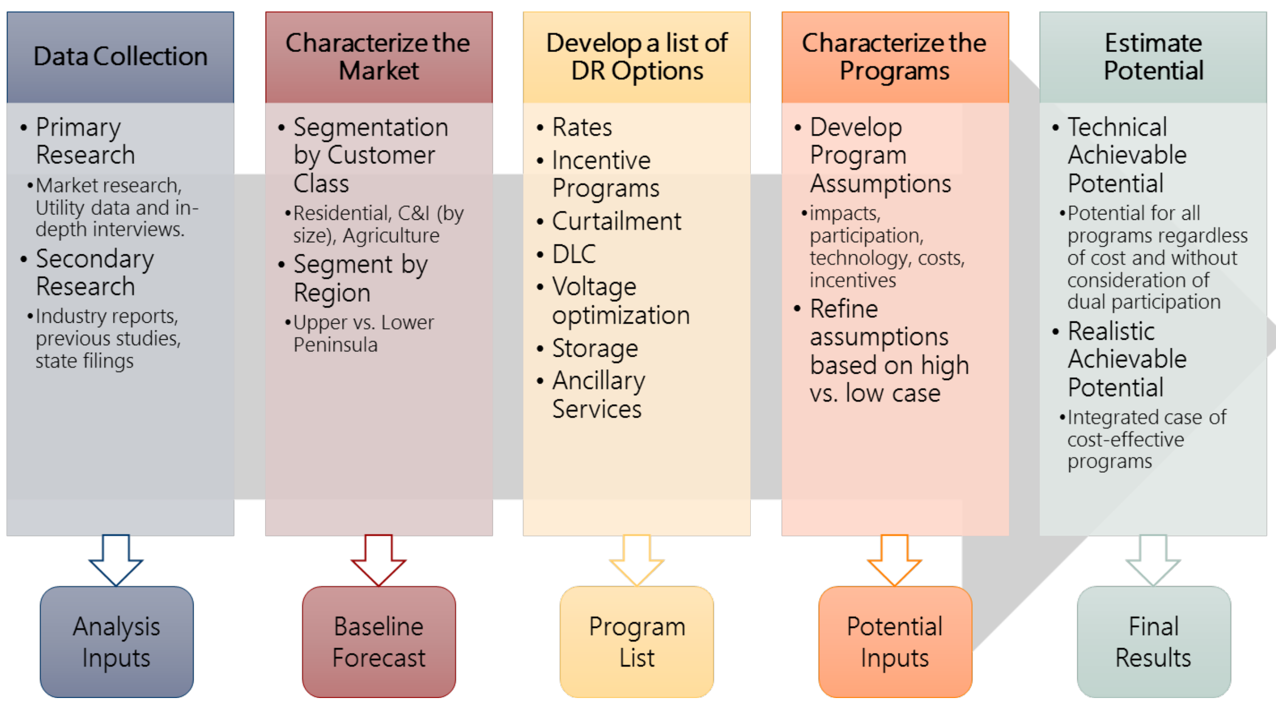
On December 21, 2016, Michigan's new energy plan was signed into law. As part of this new legislation, the Michigan Public Service Commission (MPSC) and Michigan Agency for Energy (MAE) were directed to engage in several new initiatives including a Statewide Assessment of Demand Response (DR) Potential. 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:

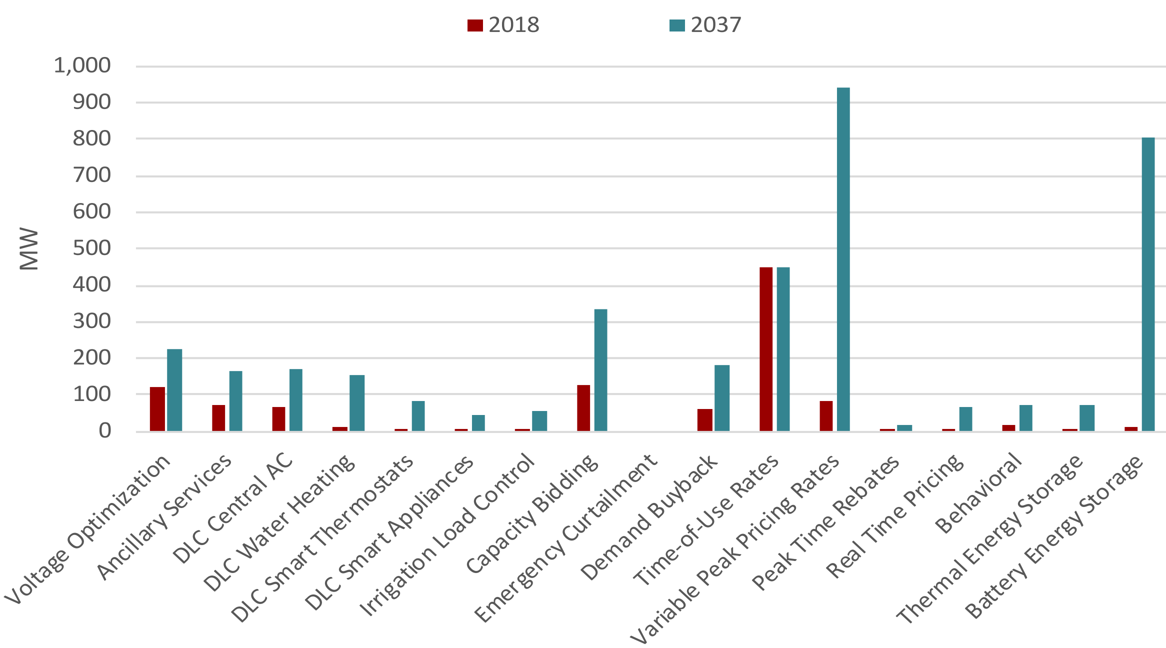
- In general, Battery Storage could be a game changer. We estimated a total potential of 806 MW in 2037 attributable to Battery Storage across the customer segments. Once batteries become cost effective, they could change the way customers use energy and how they respond to DR events.
- Variable Peak 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

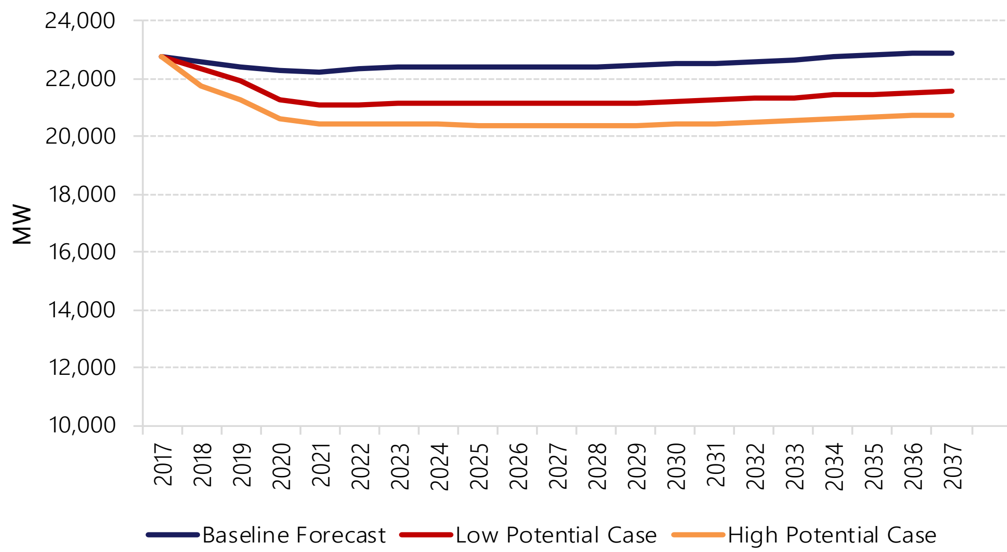
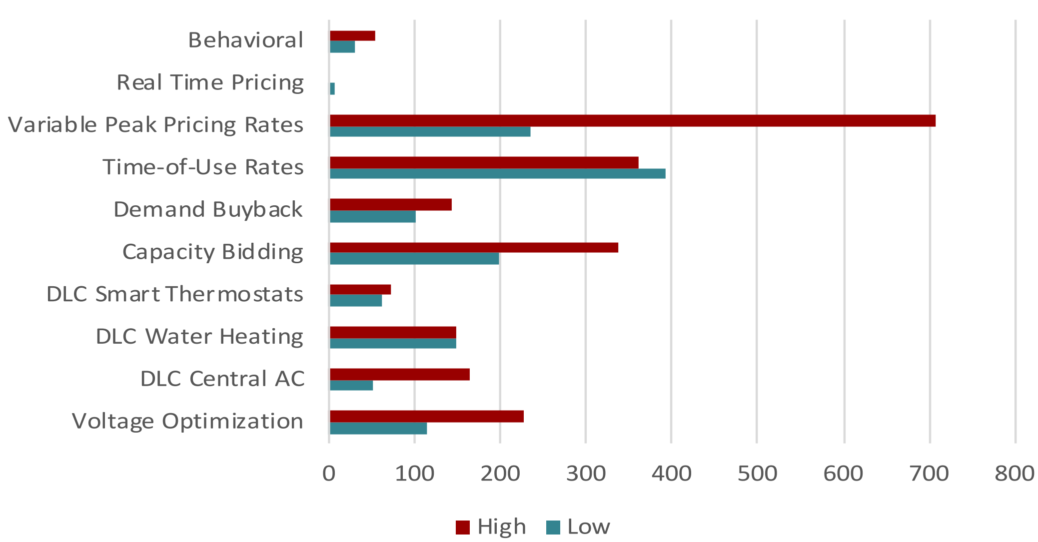


Figure E-3 Overall Potential in the High and Low Cases by Program in 2037 (MW)



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1

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.

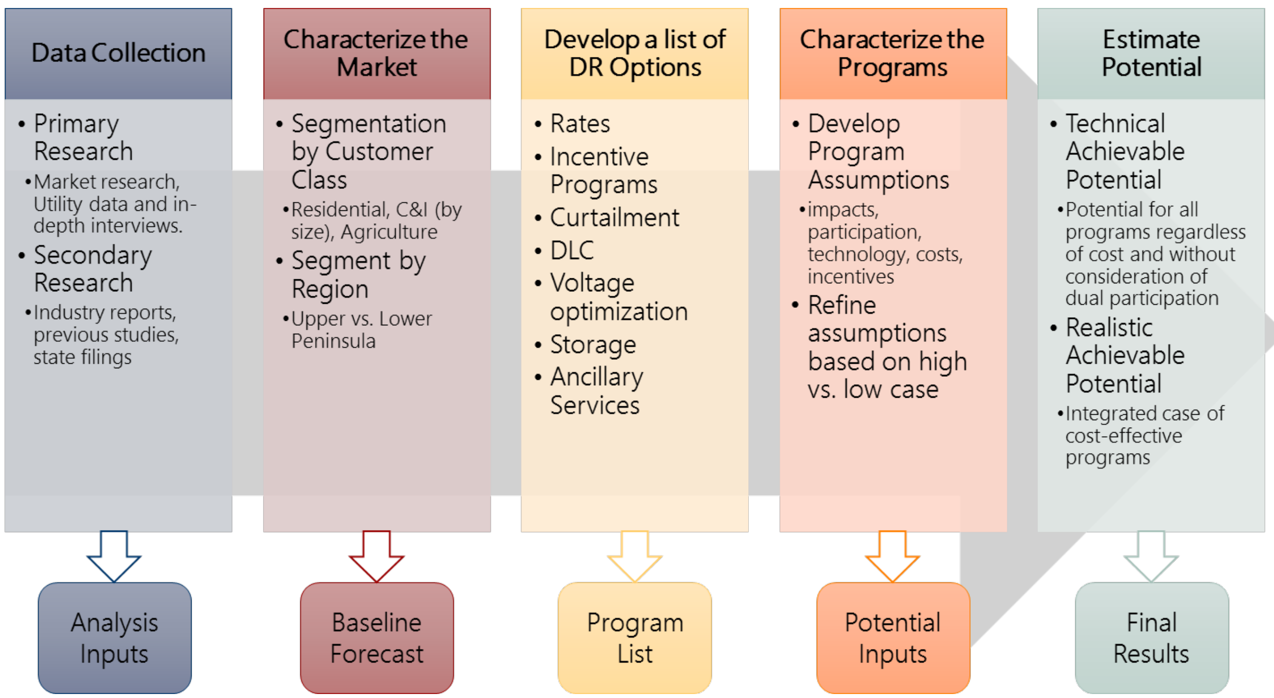
- Finally, the study was designed to provide recommendations regarding potential for demand response in the future, and regarding potential future analysis enhancements.

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.
- 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 finalizes list of DR program options which will be 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 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

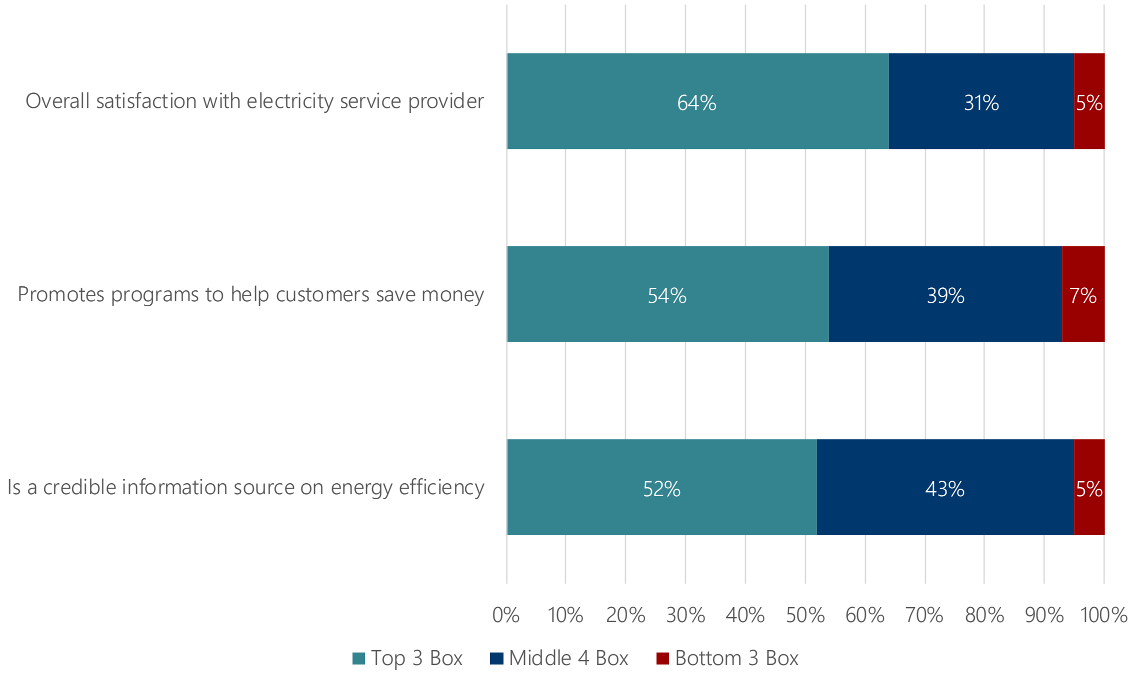
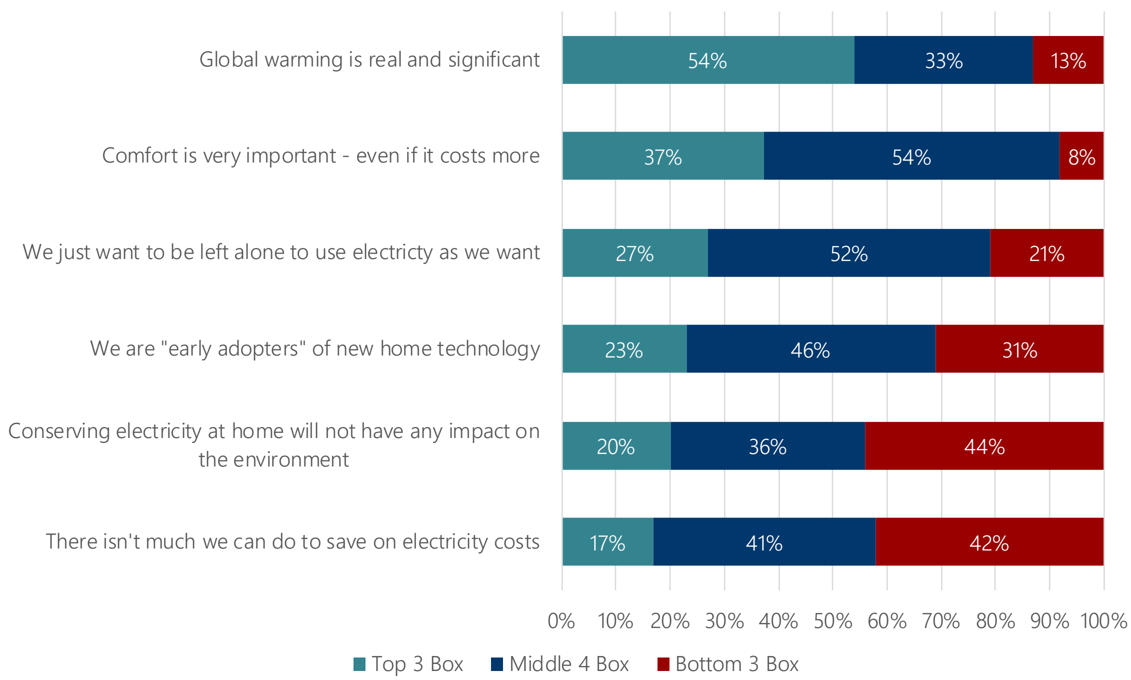


Figure 2-3 Perceptions Regarding Energy Use and Conservation



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

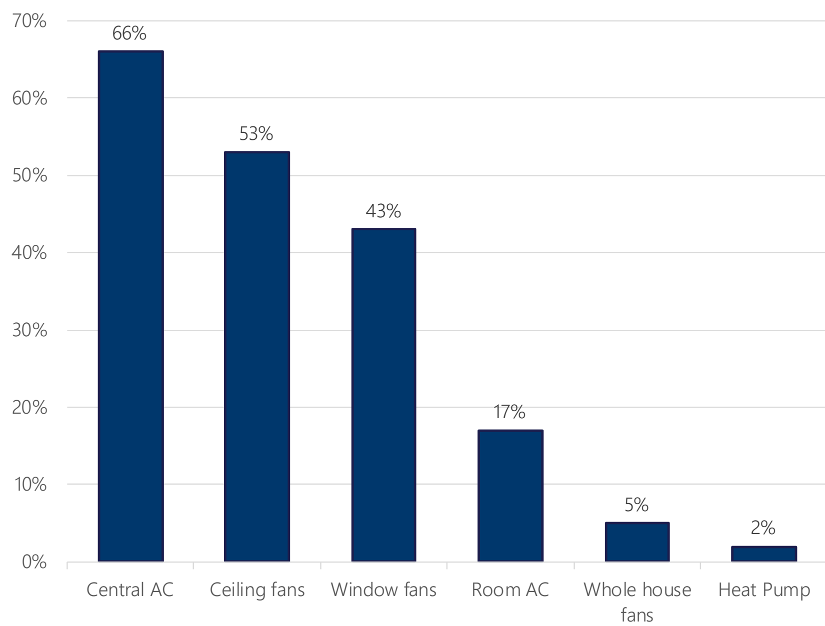


Figure 2-4 illustrates the penetration of central air conditioning, and other home cooling equipment such as fans, and room AC. It is important to note that customers could indicate that they had more than one appliance, i.e., central AC and window fans, so the percentages in the graph add up to more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

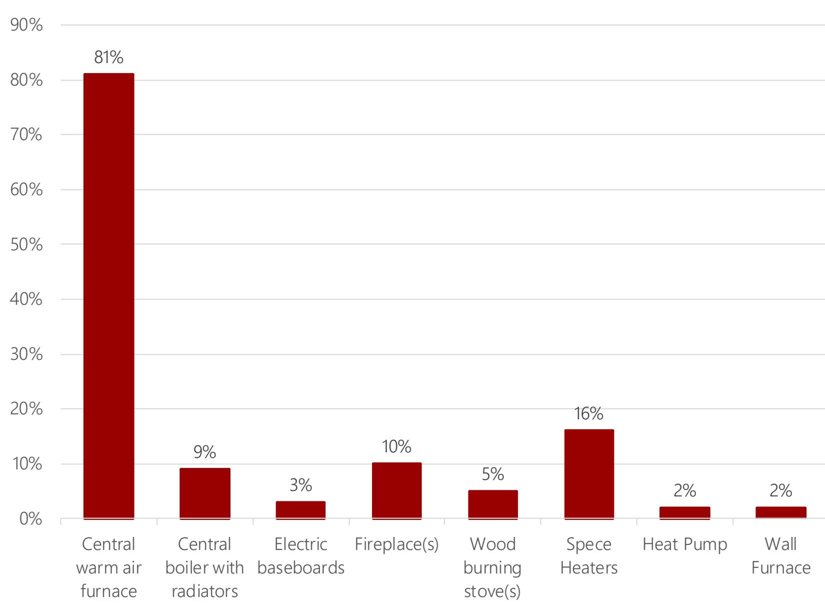
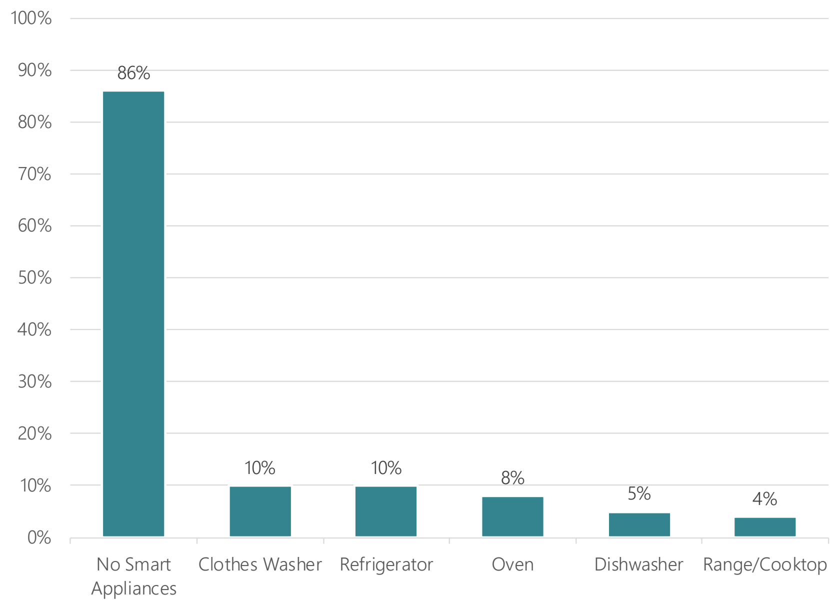


Figure 2-5 illustrates the penetrations of various types of heating equipment within customer homes. Central warm air furnaces are the most prevalent with 81% of households reporting having this type of heating system. Smaller percentages of customers have space heaters, fireplaces and central boilers,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

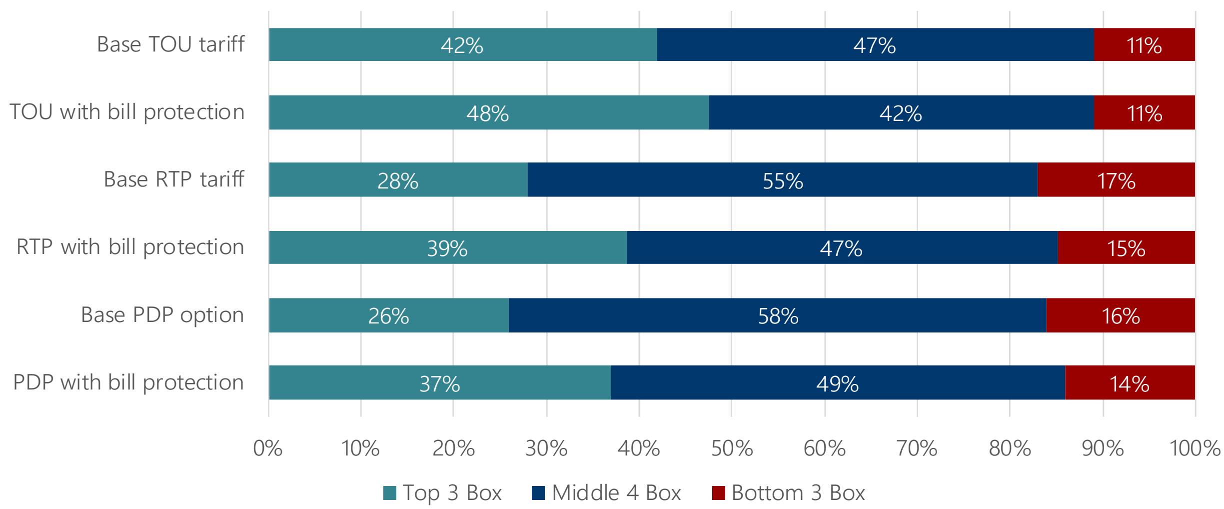
[1] A three percent penetration of electric vehicles may be on the high side, we find that customers sometimes confuse plug in hybrid vehicles with electric vehicles.

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 <u>except</u> 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



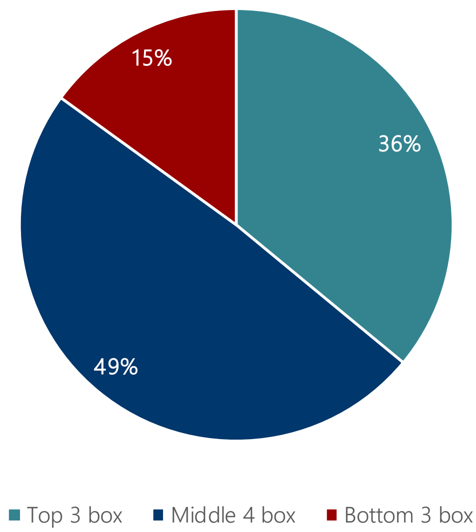
Customer Stated Interest in Direct Load Control

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

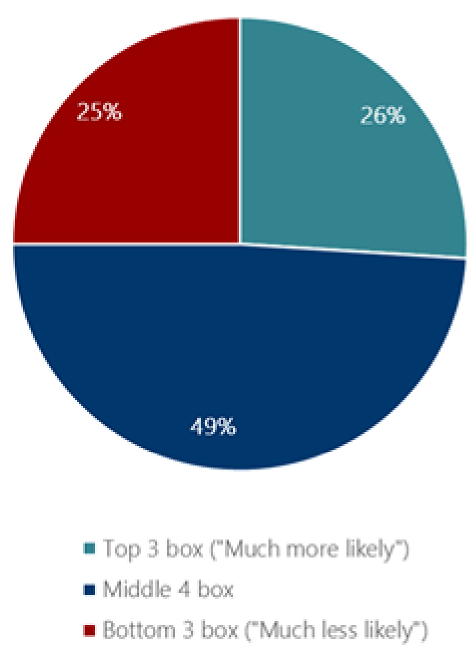


Figure 2-9 right, shows that interest in a smart thermostat version of the DLC program is similar to interest in the standard DLC program. Twenty-six (26%) percent of respondents give ratings indicating that they are "much more likely" to participate in a smart thermostat version of the DLC program compared 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]

[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 11^{th}, 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

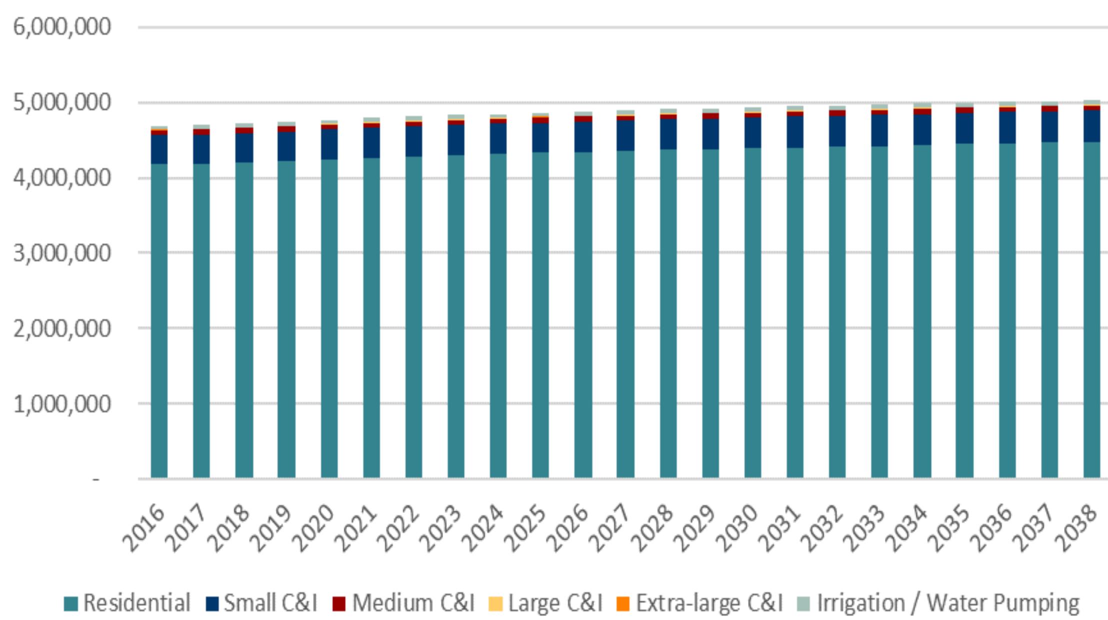


Figure 3-2 C&I Only Customer Forecast for Lower Michigan

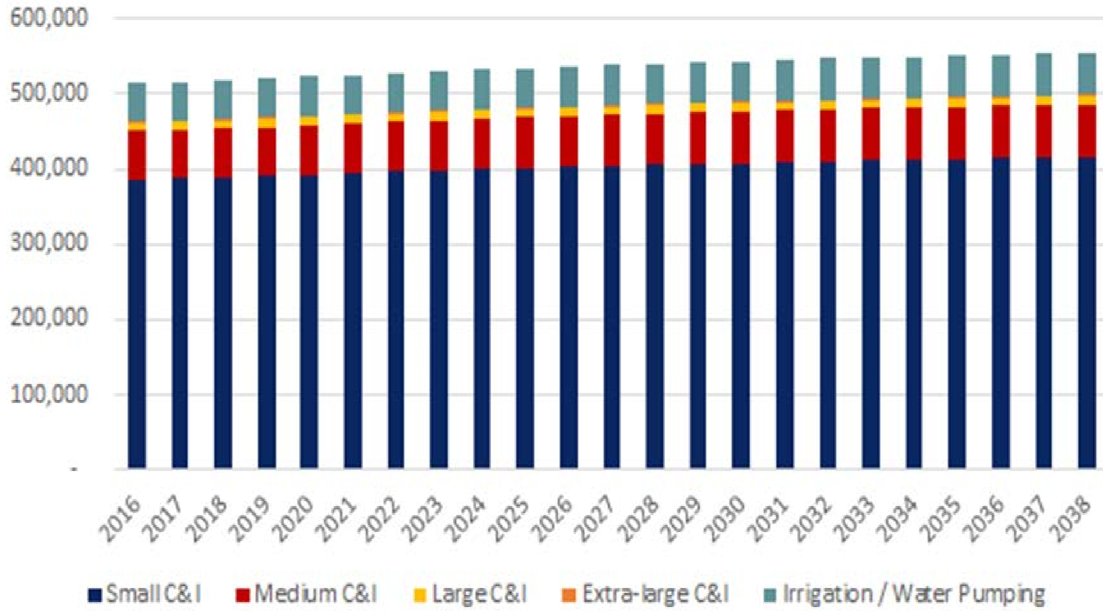


Table 3-1 Customer Forecast by Segment for Lower Michigan

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

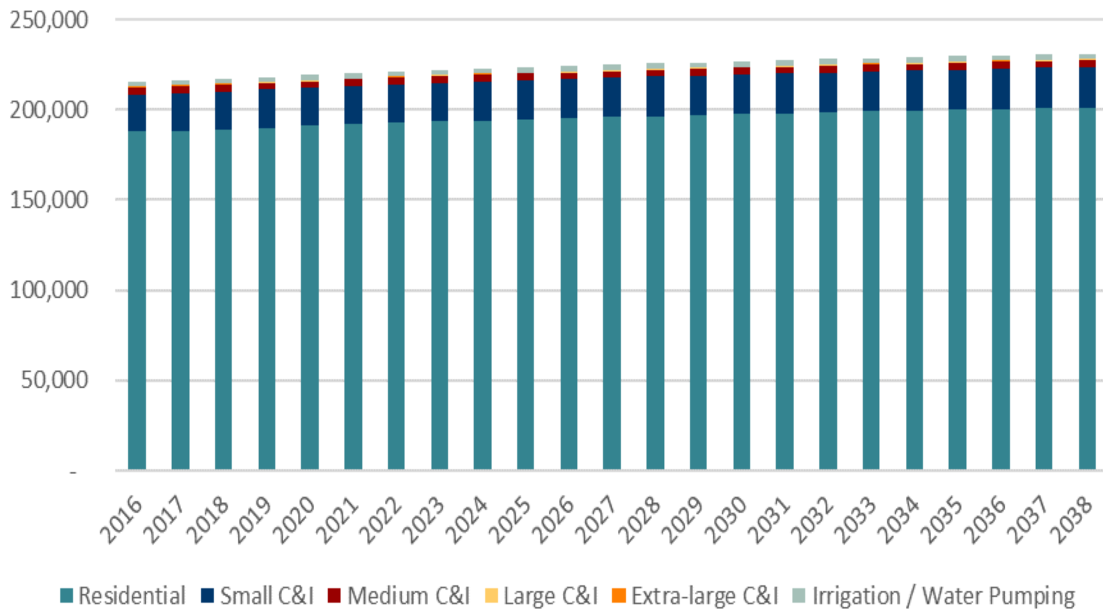


Figure 3-4 C&I Only Customer Forecast for Upper Michigan

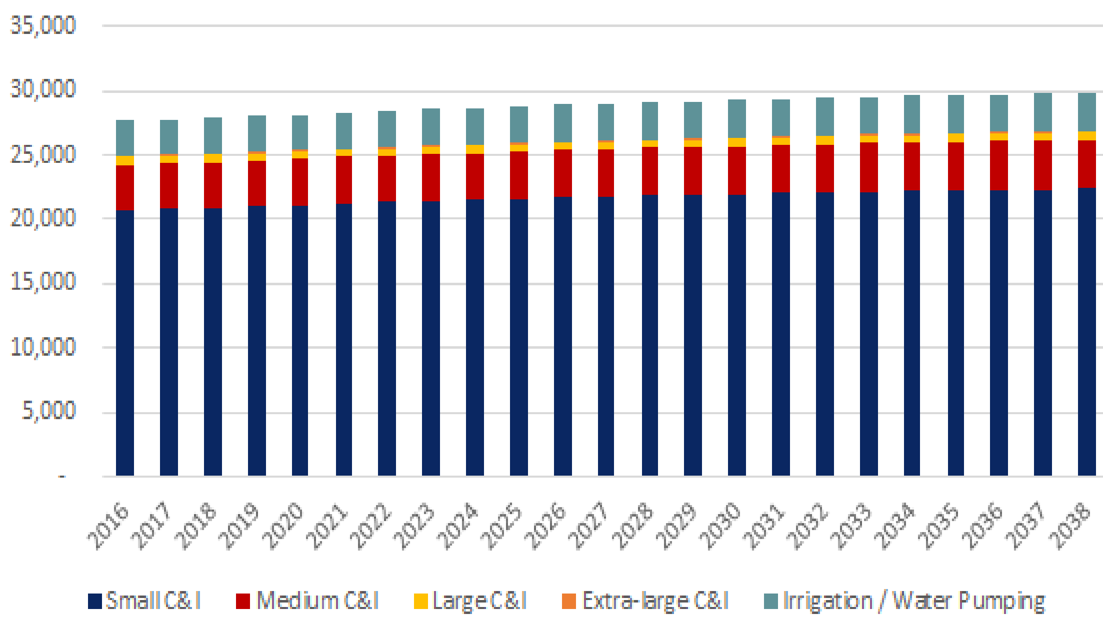


Table 3-2 Customer Forecast by Segment for Upper Michigan

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)

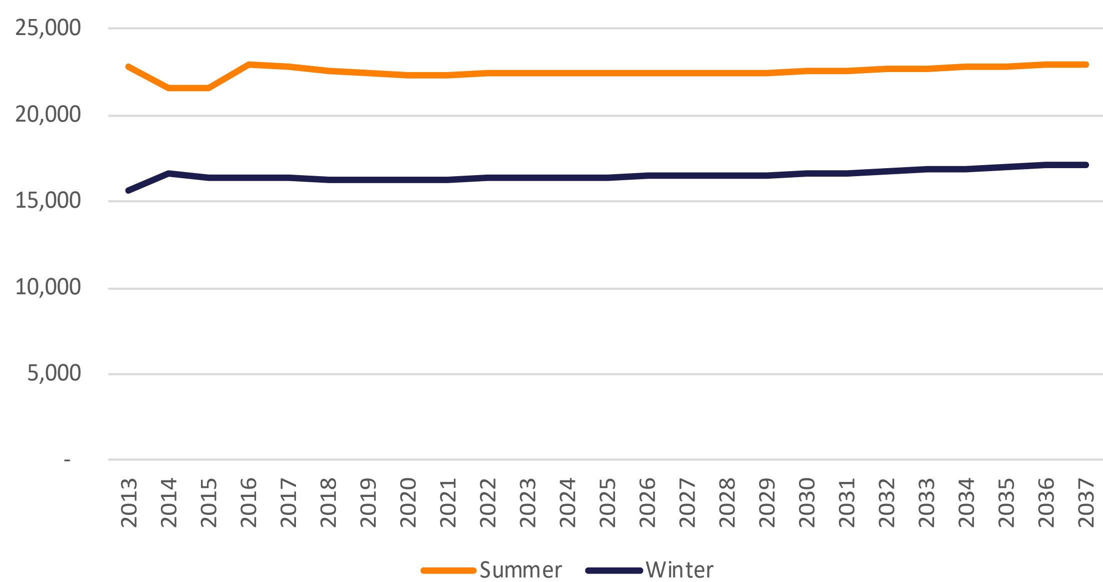


Table 3-3 Peak Demand of the State of Michigan

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)

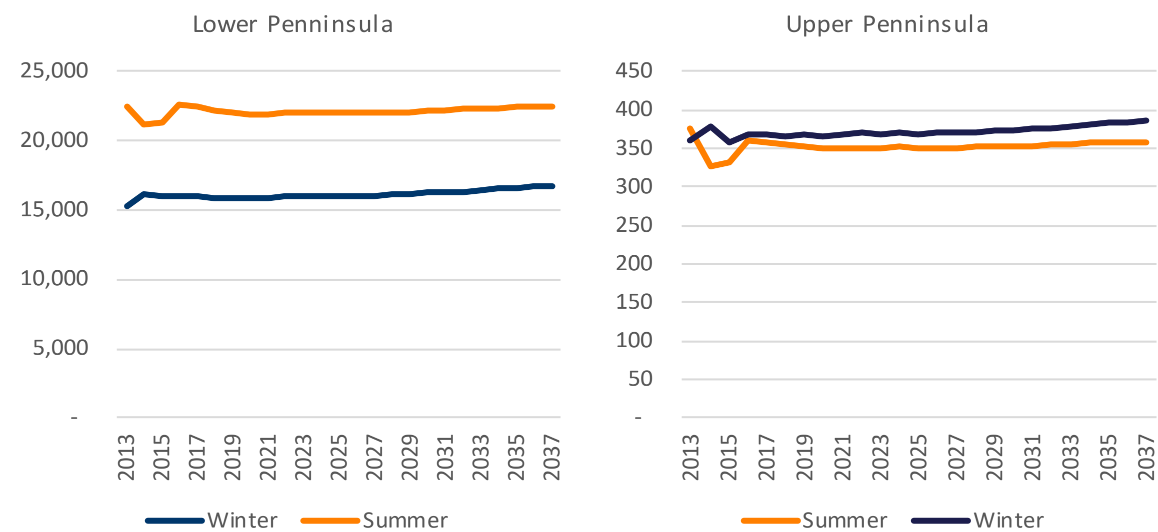


Table 3-5 Peak Demand Forecast by Region

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)

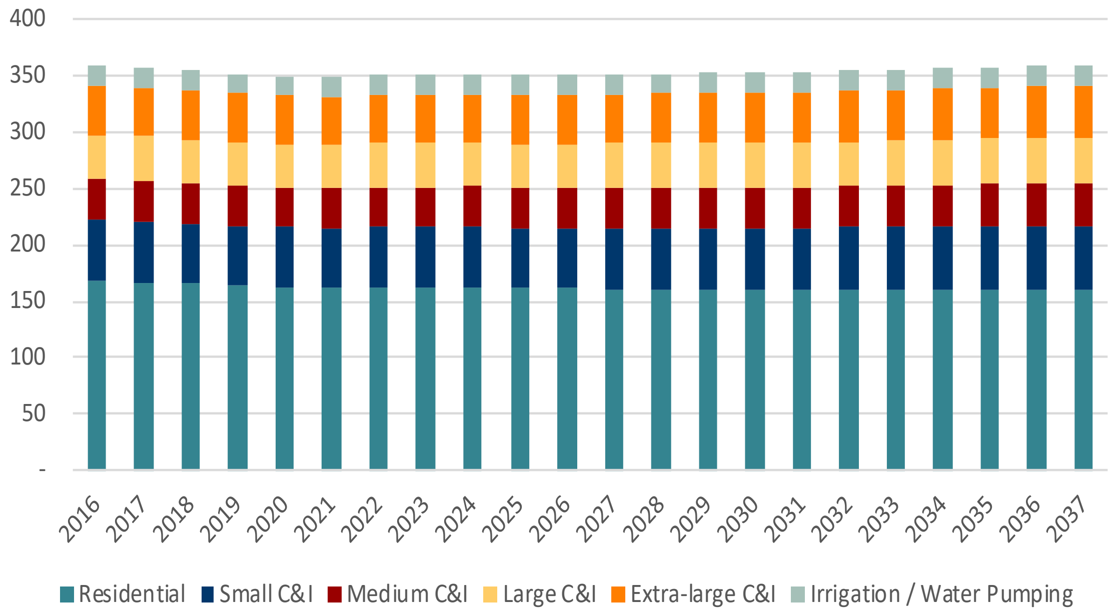


Table 3-6 Summer Peak Demand of the Upper Peninsula by Segment

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)

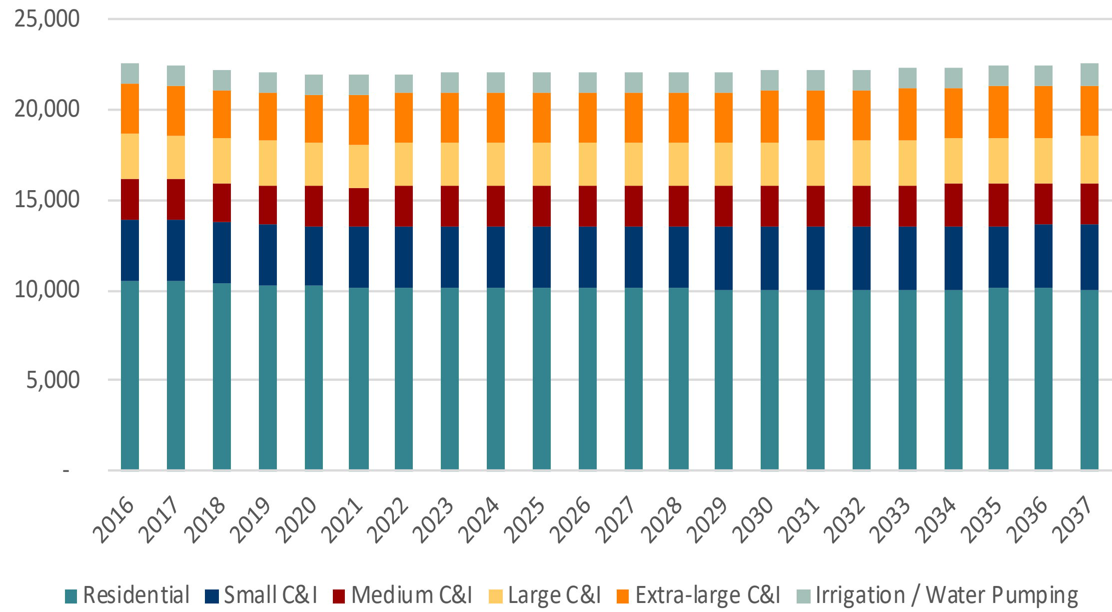


Table 3-7 Summer Peak Demand of the Lower Peninsula by Segment

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

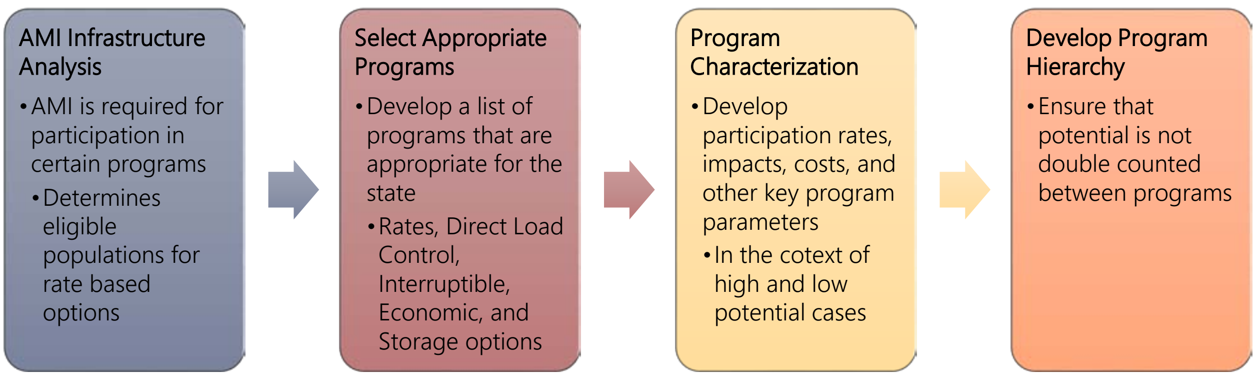
The baseline forecast sees lowering demand over the period of 2016-2019 before growth begins to slowly increase again. The effects of energy efficiency and shifting consumption patterns can be measured directly from this forecast: for a 7.2%-7.8% increase in total meters, total demand will only grow 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.

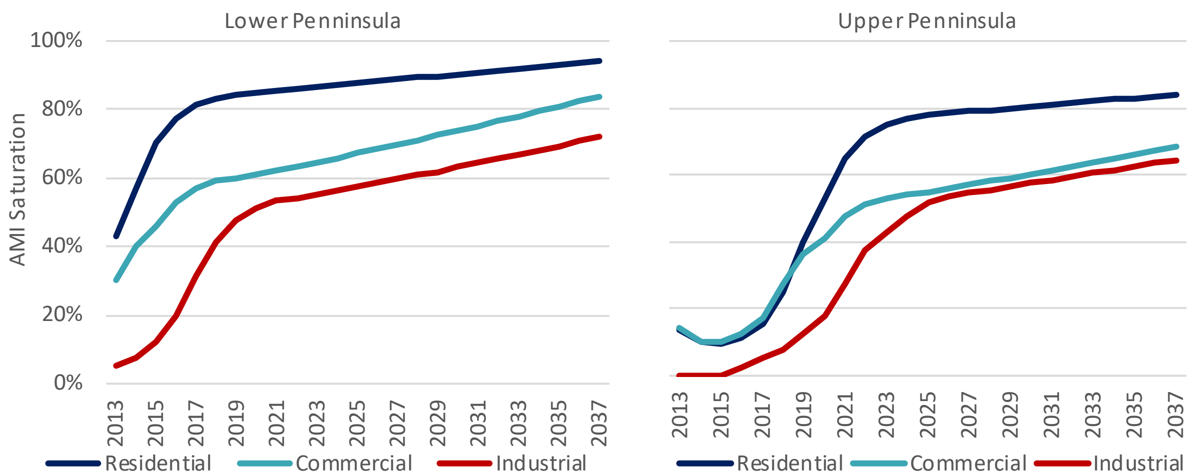
Of the 17 programs evaluated in this study, eight of them were determined to require AMI meters to operate. An additional six would benefit from AMI for evaluation and measurement purposes.

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:

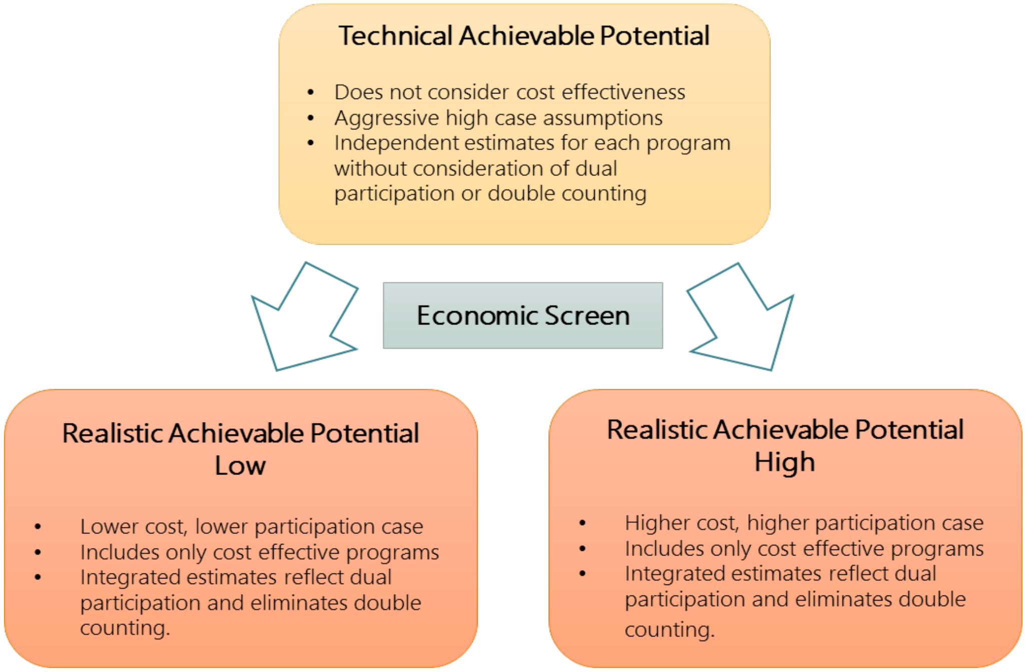
- Technical potential – the total potential that could be realized without consideration of customer willingness to adopt measures or cost effectiveness. This represents 100% participation for the eligible population of each DR program.
- Economic potential – the subset of technical potential that is 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

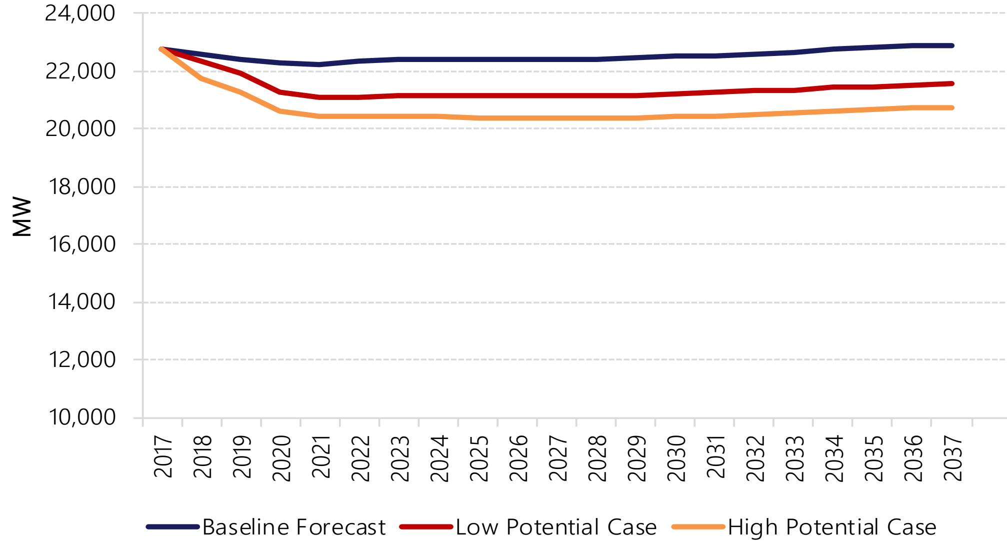
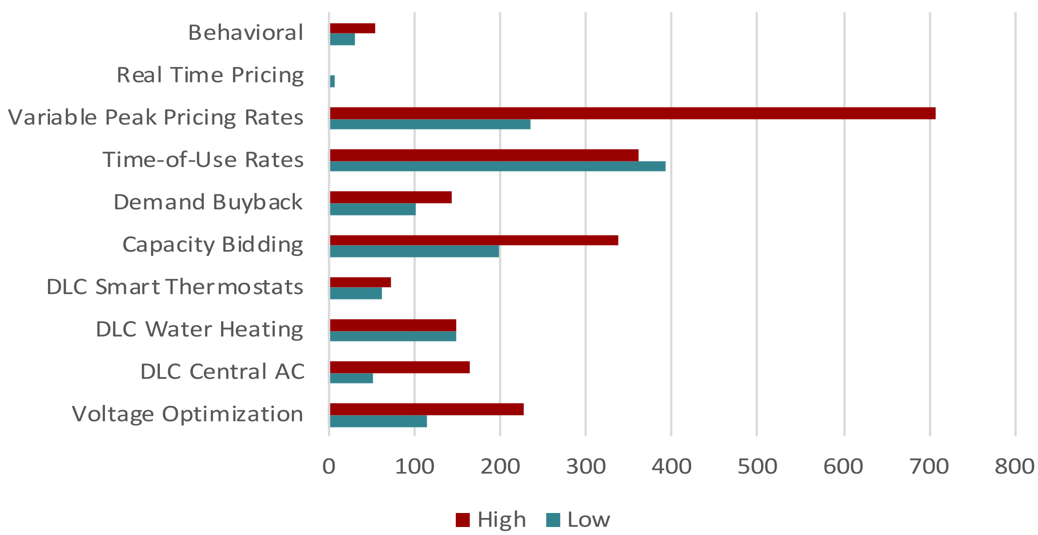


Figure 5-3 Overall Potential in the High and Low Cases by Program in 2037 (MW)



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.

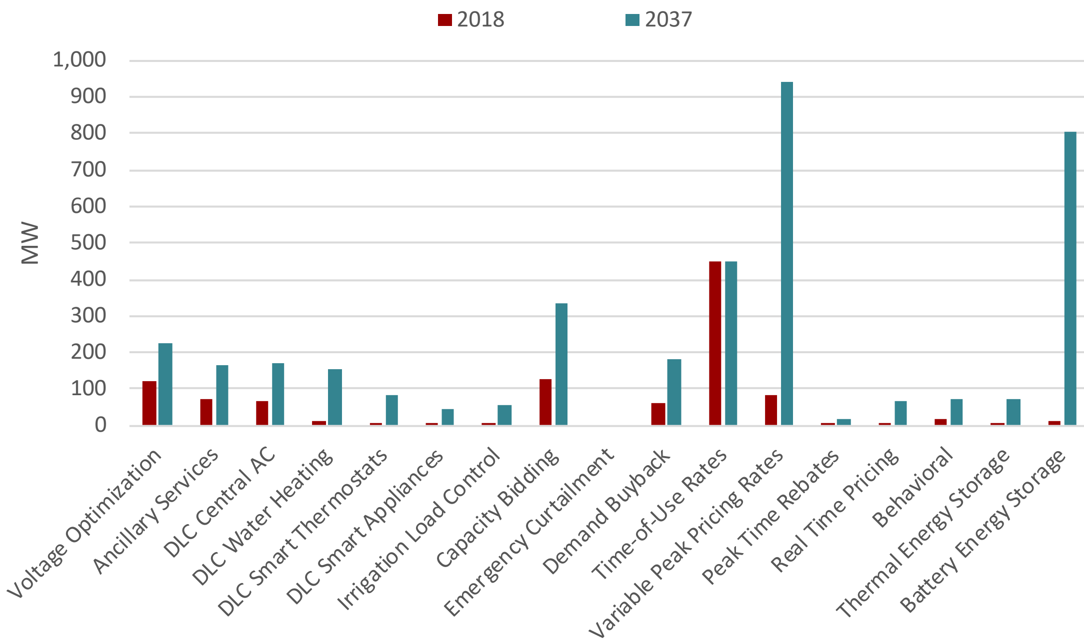
These two programs yield high levels of potential for largely opposite reasons: VPP has a lower amount of peak reduction but is widely applicable with higher participation rates, while Battery Storage has large reductions in demand but is harder to deploy widely due to capital costs and customer willingness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

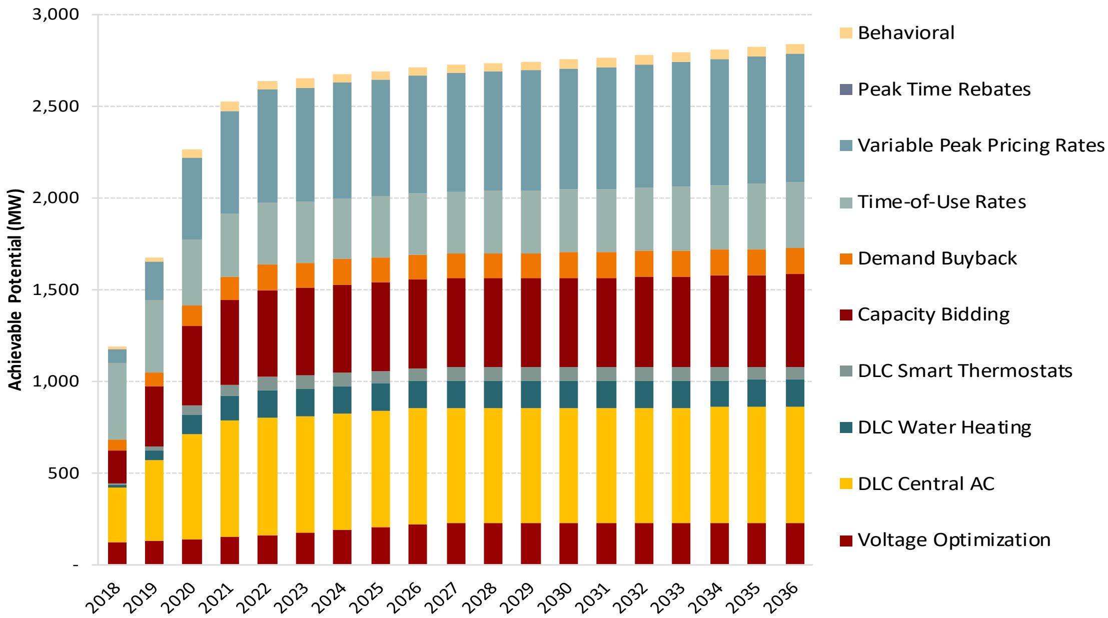
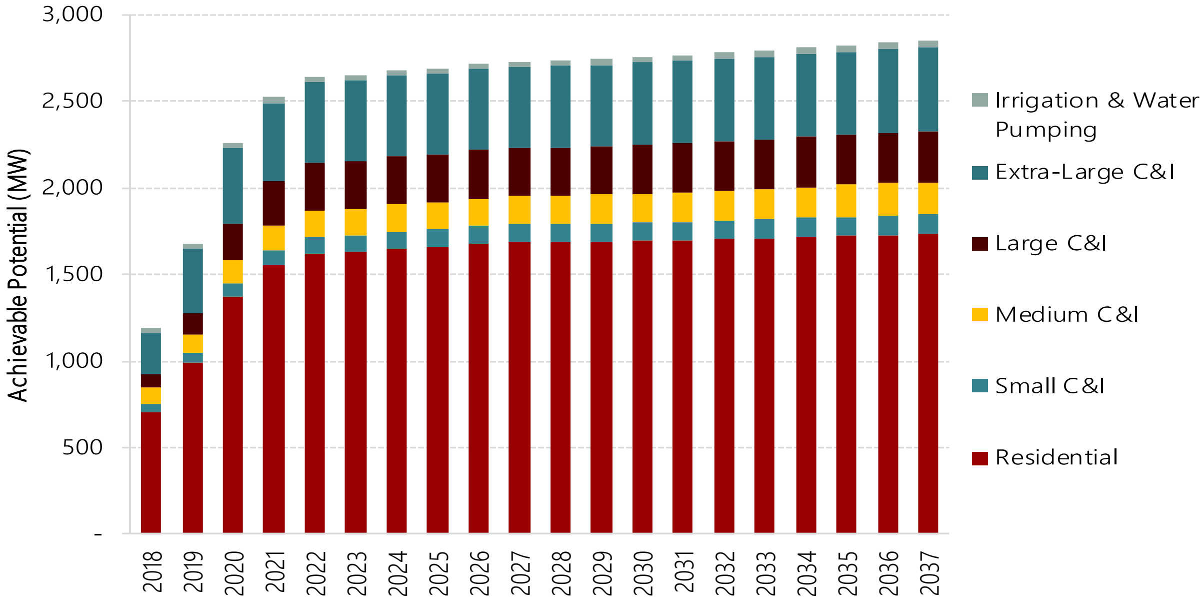


Table 5-8 and accompanying Figure 5-6 show the forecast for selected years by segment. Keep in mind that these impacts are incremental over the existing utility program offerings and assume that those programs remain in place through the end of the study.

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)

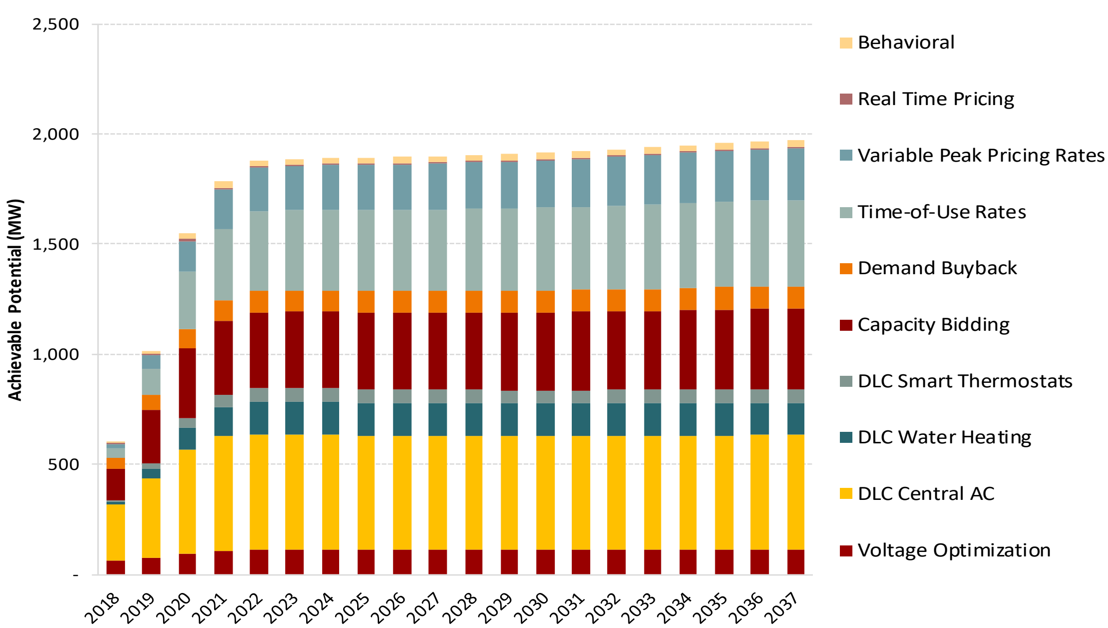
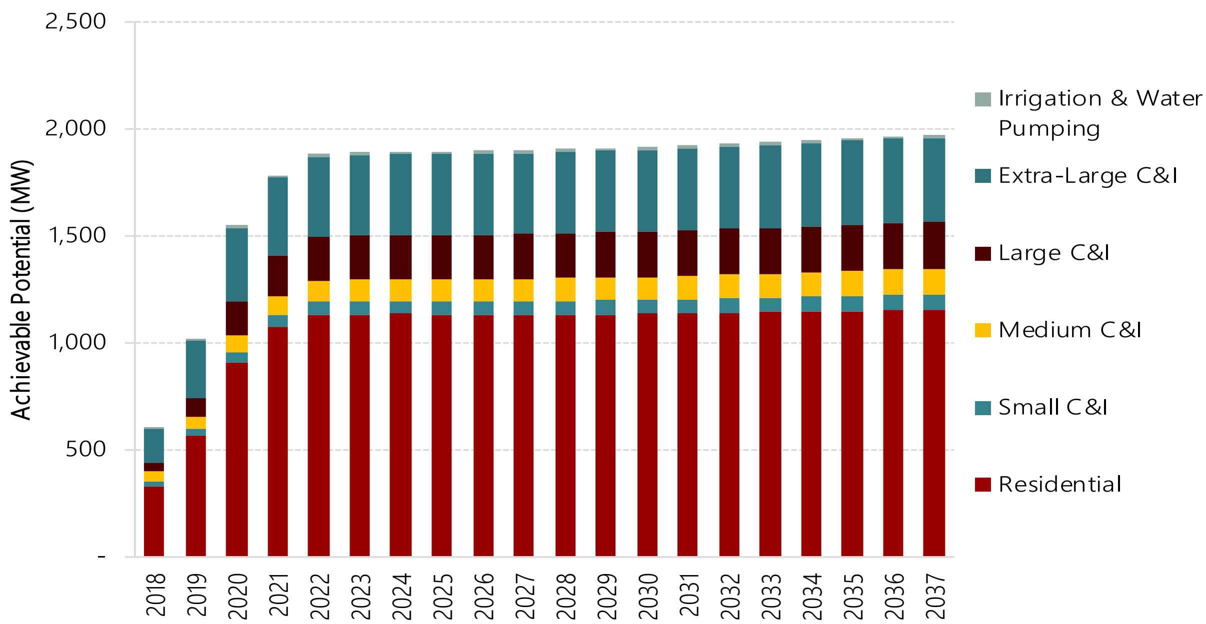


Table 5-11 and Figure 5-8 show the potential results for selected years by customer segment. Compared to the high scenario, residential again shows the biggest drop in potential. This comes from the large reduction in the adoption of VPP. Overall, this gives a total market potential for the state of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

[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 **one** 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 <u>except</u> 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 every day
2. A rate program in which electricity rates varied only on the hottest ten days of the summer
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 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
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 <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
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 <u>household's</u> 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 Generator - State of Michigan

DR_Model_State of Michigan_Standalor

DR_Model_State of Michigan_Integratec

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Michigan Public Service Commission
DTE Electric Company
2017 R/E Portfolio Projected Capacity Position

Case No. U-18419
Exhibit ELP-61 (RTB-4)
Witness: Beach
Date: January 12, 2018

Case No. U-18419
Exhibit _____
Witness: Beach

Capacity Balance with R/E Portfolio

		Demand					Supply												
	Year	Bundled Coincident Peak Demand	Additional EE Capacity	Net Peak Demand	Reserve Margin	Planning Reserve Margin Requirement	Generation Resources	Incremental Subtractions Including Coal	Incremental Wind Additions	Incremental DG Solar	Incremental Utility Fixed Solar	Incremental Utility Tracker Solar	Incremental Base Additions	Total Incremental Additions	Demand Response	Power Purchase Agrements	Total Planning Resources	Capacity Position	Change from 2017 Reference Position
	2017	10,454		10,454	412	10,866	9,929	(63)					190	190	630	190	10,876	10	-
1	2018	10,413	(52)	10,361	380	10,741	10,056	(414)	-	-	25	-	72	97	730	190	10,659	(82)	139
2	2019	10,408	(108)	10,300	360	10,660	9,739	-	27	12	25	63	242	369	844	190	11,141	482	380
3	2020	10,385	(168)	10,217	359	10,576	10,108	(230)	36	12	25	63	146	283	969	190	11,320	744	685
4	2021	10,398	(229)	10,169	370	10,539	10,160		25	12	12	63	237	350	1,027	190	11,728	1,189	896
5	2022	10,392	(289)	10,103	379	10,482	10,511	(850)	25	12	12	63	56	169	1,054	190	11,074	592	565
6	2023	10,390	(246)	10,144	389	10,533	9,830	(785)	13	12	12	32	36	105	1,055	190	10,395	(138)	61
7	2024	10,387	(154)	10,233	389	10,622	9,150		6	12	12	32	6	69	1,055	190	10,463	(159)	31
8	2025	10,371	(88)	10,283	399	10,682	9,219		6	12	12	32	-	63	1,054	190	10,526	(157)	27
9	2026	10,357	(41)	10,316	408	10,724	9,281		-	12	12	32	-	56	1,055	190	10,583	(141)	37
10	2027	10,341	(4)	10,337	408	10,745	9,338		-	-	-	-	-	-	1,055	190	10,582	(163)	(1)
11	2028	10,329	-	10,329	407	10,736	9,338		-	-	-	-	-	-	1,054	190	10,582	(154)	(5)
12	2029	10,308	-	10,308	406	10,714	9,338	(484)	-	-	-	-	-	-	1,059	190	10,102	(612)	(1)
13	2030	10,288	-	10,288	405	10,693	8,854	(509)	-	-	-	-	-	-	1,058	190	9,593	(1,100)	(1)
14	2031	10,268	-	10,268	405	10,673	8,345	-	-	-	-	-	-	-	1,058	190	9,592	(1,081)	(2)
15	2032	10,250	-	10,250	404	10,654	8,345	-	-	-	-	-	-	-	1,057	190	9,592	(1,062)	(2)
16	2033	10,226	-	10,226	403	10,629	8,345	-	-	-	-	-	-	-	1,056	190	9,591	(1,038)	(3)
17	2034	10,203	-	10,203	402	10,605	8,345	-	-	-	-	-	-	-	1,061	190	9,595	(1,010)	1
18	2035	10,176	-	10,176	401	10,577	8,345	-	-	-	-	-	-	-	1,060	190	9,595	(982)	1
19	2036	10,150	-	10,150	400	10,550	8,345	-	-	-	-	-	-	-	1,059	190	9,594	(956)	(0)
20	2037	10,118	-	10,118	399	10,517	8,345	-	-	-	-	-	-	-	1,058	190	9,593	(924)	(1)
21	2038	10,087	-	10,087	397	10,484	8,345	-	-	-	-	-	-	-	1,059	190	9,594	(890)	(0)
22	2039	10,086	-	10,086	397	10,483	8,345	(1,392)	-	-	-	-	-	-	1,059	190	8,202	(2,281)	(0)
23	2040	10,090	-	10,090	397	10,487	6,953	(1,422)	-	-	-	-	-	-	1,059	190	6,780	(3,707)	(0)
24	2041	*10,094*	-	10,094	397	10,491	5,531	-	-	-	-	-	-	-	1,059	190	6,780	(3,711)	(0)
25	2042	*10,098*	-	10,098	397	10,495	5,531	-	-	-	-	-	-	-	1,059	190	6,780	(3,715)	(0)

Methane Leaks from Natural Gas Infrastructure Serving Gas-fired Power Plants

Andrew B. Peterson
R. Thomas Beach
Crossborder Energy
February 19, 2016

1. Summary

Natural gas has been commonly depicted as a “bridge” fuel between coal and renewable energy for the generation of electricity. Natural gas is considered more environmentally friendly because burning natural gas produces less CO_2 than coal on a per unit of energy basis. Most analyses of the greenhouse gas (GHG) emissions associated with burning natural gas to produce electricity use an emission factor of 117 lbs of CO_2 per MMBtu of natural gas burned. However, this number does not include methane leaked to the atmosphere during the production, processing, and transmission of natural gas from the wellhead to the power plant. Methane is both the primary constituent of natural gas and a potent greenhouse gas (GHG), so quantifying the methane leakage is important in assessing the impact of natural gas systems on global warming.

Methane is emitted to the atmosphere from natural gas systems in both normal operating conditions and in low frequency, high emitting incidents. The Environmental Protection Agency’s (EPA) “Inventory of U.S. Greenhouse Gas Emissions and Sinks” attempts to calculate methane emissions from natural gas systems using a “Bottom Up” accounting method, which essentially adds up methane emissions from production, processing, transmission, storage, and distribution. This method sets a reasonable baseline for methane emissions during normal operating conditions, but does not account for low frequency high emitting situations.

Low frequency high emitting situations happen when some part of the production, processing, or transmission systems fail, leaking large amounts of methane into the atmosphere. The recent Aliso Canyon leak from a major Southern California Gas storage field in Parker Ranch, California is probably the best-known example of a low frequency high emitting event. The Aliso Canyon leak has emitted 2.4 MMT CO2-eq., or roughly 1.5% of total yearly methane emissions from all U.S. natural gas Infrastructure, in a single event. Several studies have shown that low frequency high emitting events like Aliso Canyon contribute significantly to methane emissions from natural gas systems.

The following analysis and discussion lays out an argument for increasing the carbon emission factor for burning natural gas in power plants to include the carbon equivalent of the methane emitted in the production, processing, transmission, and storage of natural gas,

leaving out the losses in local distribution that are downstream from power plants on the gas system. A conservative starting point for the leakage from wellhead to power plant is that 2% of natural gas produced is lost to leakage in the form of methane. This estimate is based the IPCC Fifth Assessment Report, the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," adjusted based on several studies quantifying how the EPA's method underestimates actual emissions.

Using the conservative estimates of 2% of total production emitted, and a global warming potential (GWP) of 25 (the low end of methane's GWP) increases the CO_2 emitted by burning methane to 175.5 lbs of CO_2-eq. per MMBtu of natural gas burned (a factor of 1.5). Using a GWP of 34 (high end) yields 196.6 lbs of CO_2 per MMBtu of natural gas burned (a factor of 1.68).

2. Measuring Natural Gas Leakage (Methods)

Determining methane leaks from natural gas systems is relatively new field of study. Until 2011 methane leaks were calculated almost exclusively using a Bottom Up accounting method based on data published in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks". Several issues with this method, including outdated Emission Factors and low frequency high emitting events, have led researchers to use "Top Down" aerial measurements of methane leakage.

Bottom Up. Bottom Up (BU) methods attempt to identify all sources of methane emissions in a typical production chain and assign an Emission Factor (EF) to each source. The total emissions are determined by adding up all of the EFs through the life cycle of natural gas. BU measurements are useful because they avoid measuring methane from biogenic sources (landfills, swamps, etc), anthropogenic sources in geographic proximity to natural gas systems (coal plants, oil wells, etc), and only require an engineering inventory of equipment and activity. However, BU measurements often rely on decades-old EFs. The EFs used in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks" are based on a report published in 1996, which in turn is based on data collected in 1992. The EPA has developed a series of correction factors based on technological improvements and new regulations.

BU studies have been shown to underestimate methane emissions from natural gas systems.[1]–[5] While outdated EFs can cause both under and overestimation of emissions, low frequency high emission events are responsible for consistent underestimation of emissions by BU calculations.[1], [5]–[7] A recent study in the Barnett Shale region of Texas found that 2% of facilities were responsible for 50% of the emissions and 10% were responsible for 90% of the emissions.[5] BU measurements do not accurately take into account these low frequency high emitters. First, most BU measurements either sample only a few facilities or rely on facility and equipment inventories rather than local measurements. Secondly, most BU data is selfreported. Finally, several studies have found that the low frequency high emitters were both spatially and temporally dynamic, with the high emission rates resulting from equipment breakdowns and failures, and not from design flaws in a few facilities.

Top Down. Top Down (TD) methane measurements have used aerial flyovers to measure the atmospheric methane content, then use mass balance and atmospheric transport models to determine methane emissions from a geographical region. A signature compound such as ethane is used to distinguish fossil methane from biogenic methane. Unlike BU measurements, TD measurements account for low frequency high emitter situations. TD studies consistently measure higher levels of methane emissions than do BU studies. Only recently have measurements TB and BU studies converged, and this convergence was only after additional low frequency high emission situations were characterized in BU studies.[5]

3. Methane Leak Calculations

The EPA divides methane emissions from natural gas systems into four categories: Field Production, Processing, Transmission and Storage, and Distribution. This analysis focuses on only the first three categories, leaving out local distribution networks. Detailed descriptions of these categories can be found in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."

US Natural Gas Production 2005 - 2013

Expressed as BCF Natural Gas

Source	2005	2009	2010	2011	2012	2013
Withdrawals from Gas Wells	16,247	14,414	13,247	12,291	12,504	10,760
from Shale Shale Wells	0	3,958	5,817	8,501	10,533	11,933
Total Withdrawals from Natural Gas Systems	16,247	18,373	19,065	20,792	23,037	22,692

Emissions from US Natural Gas Systems 2005 - 2013

Expressed as % of Total Production

Stage	2005	2009	2010	2011	2012	2013
Field Production	0.91	0.66	0.58	0.48	0.42	0.41
Processing	0.20	0.20	0.18	0.20	0.19	0.20
Transmission and Storage	0.59	0.56	0.53	0.51	0.44	0.47
Total	1.70	1.43	1.30	1.19	1.05	1.07

Using the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks," methane emissions from natural gas infrastructure from the wellhead to a gas-fired power plant (excluding local distribution) are currently estimated to be 1.1% of production.[8] Given that EPA uses a BU method for calculating emissions, it is reasonable to assume that 1.1% is an underestimation. A 2015 study that combined seven different datasets from both TD and BU and included the most aerial measurements to date concluded that methane emissions were 1.9 (1.5 – 2.4) times the number reported in the EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks."[5] If the EPA's estimate is multiplied by 1.9 the result is 2.09%.

The IPCC Fifth Annual Report agrees, stating that: "Central emission estimates of recent analyses are 2% - 3% (+/– 1%) of the gas produced, where the emissions from conventional and unconventional gas are comparable." [9]

4. Global Warming Potential of Natural Gas

Global warming potentials (GWP) provide a method of comparing different GHGs. A GWP is: "a relative measure of how much heat a greenhouse gas traps in the atmosphere. It compares the amount of heat trapped by a certain mass of the gas in question to the amount of heat trapped by a similar mass of carbon dioxide." The Intergovernmental Panel on Climate Change (IPCC) regularly publishes updated GWPs based on the most current scientific knowledge. The most current value for methane (based on the 2013 IPCC AR5) is 34.[9] The previous value (based on the 2007 IPCC AR4) is 25. Policy makers continue to tend to use the values closer to 25.[9] For example, the EPA uses 25 in its "Inventory of U.S. Greenhouse Gas Emissions and Sinks," but 34 is more commonly used in the scientific literature.[10]

5. Conclusion

This report recommends the use of a 2% emissions rate for methane leakage from natural gas systems when calculating the GHG emissions associated with natural gas-fired electric generation. Current analyses use 117 lbs of CO2 per MMBtu as the emissions factor from burning natural gas, which essentially assumes zero leakage. Adopting a 2% emission rate would increase this number to 175.5 lbs of CO2 per MMBtu of natural gas burned, assuming a conservative GWP of 25.

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STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

DIRECT TESTIMONY OF

PHILIP JORDAN

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

Q. What is your name and business address?

A. My name is Philip Jordan, and my business address is 19 Kendrick Street, Wrentham, Massachusetts 02093.

Q. Please describe BW Research.

A. BW Research Partnership is an economic research consultancy with offices in California and Massachusetts. We primarily focus on economic and workforce development research, including surveys, economic modeling, data analytics, and qualitative research and analysis.

Q. What is your experience and expertise as it relates to the testimony you are presenting in the case?

A. I have a decade of experience conducting labor market analyses, and I am a principal of the firm, leading our energy-related research. I have designed and managed more than 50 energy-related labor studies for dozens of public and private sector clients.

Q. What is your educational background?

A. I have a Bachelor of Arts degree from the University of Connecticut and a Juris Doctor from Boston College.

Q. What is the purpose of your testimony?

A. BW Research was commissioned by Vote Solar to produce an economic impact analysis of the direct construction and operations jobs associated with approximately 2,500 megawatts (MW) of renewable power plant production and efficiency savings in the state of Michigan. BW Research applied proprietary labor efficiency data produced from years of studying clean economies in the region to calculate the direct impact of the added energy capacity and savings. Vote Solar provided the total MW of proposed wind, distributed solar, and utility-scale solar energy capacity, and the total proposed MW associated with added energy efficiency capacity for the state of Michigan. BW Research used these proposed MW of added energy capacity and energy efficiency to calculate the following:

- Construction jobs associated with wind energy capacity addition;
- Operations and maintenance jobs associated with wind energy capacity addition;
- Construction jobs associated with solar energy capacity addition;
- Operations & maintenance (O&M) jobs associated with solar energy capacity addition; and
- Industry jobs associated with the added energy efficiency capacity.

Q. Please summarize your findings.

A. We found that the portfolio of wind, solar, and energy efficiency would create 5,779 direct jobs, of which 5,642 are construction/installation jobs and 137 are ongoing operating and maintenance jobs. In addition, we found that the economic activity created if DTE were to invest in this clean energy portfolio would create another 2,582 indirect jobs in the supply chain, and 7,998 induced jobs in the broader economy.

Q. What methodology did you use to perform your analysis?

A. As described further in the summary memo we have attached as Exhibit ELP-63 (PJ-1), we used proprietary labor efficiency data produced from years of studying clean economies in the region to calculate the direct impact of the added energy capacity and savings. The economic impact analyses were developed using Emsi's input-output model, a model that traces spending and infrastructural developments through the economy. The cumulative effects of the initial jobs created are measured and the results are categorized into direct, indirect, and induced effects. Jobs in this analysis include full- and part-time wage and salaried jobs and self-employed jobs. Full- and part-time jobs are counted equally, i.e. job counts are not adjusted to full-time equivalents. The input-output model also calculates the fiscal impact of the initial jobs created by estimating the taxes on production and imports (TPI). These taxes consist of tax liabilities, such as general sales and property taxes, that are chargeable to business expenses.

Q. Does this conclude your testimony?

A. Yes it does.

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	)	Case No. U-18419

EXHIBIT OF

PHILIP JORDAN

ON BEHALF OF

ENVIRONMENTAL LAW AND POLICY CENTER, THE ECOLOGY CENTER, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, VOTE SOLAR, AND THE UNION OF CONCERNED SCIENTISTS

January 12, 2018

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MEMORANDUM

To: **Vote Solar**

From: **BW Research**

Date: **December 11th, 2017**

Re:

INTRODUCTION

BW Research was commissioned by Vote Solar to produce an economic impact analysis of the direct, construction and operations jobs associated with approximately 2,500 megawatts (MW) of renewable power plant production and efficiency savings in the State of Michigan. BW Research applied proprietary labor efficiency data produced from years of studying clean economies in the region to calculate the direct impact of the added energy capacity and savings. Vote Solar provided the total MW of proposed wind, distributed solar, and utility-scale solar energy capacity, and the total proposed MW associated with added energy efficiency capacity for the State of Michigan. BW Research used these proposed MW of added energy capacity and energy efficiency to calculate the following:

- Construction jobs associated with wind energy capacity addition
- Operations and maintenance jobs associated with wind energy capacity addition
- Construction jobs associated with solar energy capacity addition
- Operations & maintenance (O&M) jobs associated with solar energy capacity addition
- Industry jobs associated with the added energy efficiency capacity

BW Research applied Economic Modelling Specialists (Emsi) multipliers to these inputs to determine the number of indirect and induced jobs and related fiscal impacts associated with the new capacity additions. The results of these analyses are presented below.

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ENERGY JOBS

The proposed energy capacity added to the State of Michigan includes 1,100MW of wind energy, 1,100 MW of solar energy (200MW of distributed generation and 900MW of utility-scale solar energy), and 87MW of savings from energy efficiency. BW Research applied proprietary labor efficiency data produced from years of studying clean economies in the region to calculate jobs per MW of energy capacity.

WIND ENERGY JOBS

Wind energy construction and operations jobs were calculated using research conducted by BW Research for a variety of clients over the past several years, including labor market analyses for the National Renewable Energy Laboratory (https://www.nrel.gov/docs/fy13osti/57512.pdf; https://www.nrel.gov/docs/fy14osti/61251.pdf) and the Natural Resources Defense Council (https://www.nrdc.org/sites/default/files/american-wind-farms-IP.pdf). These findings were used to develop a custom model for the number of jobs associated with each MW of added wind energy capacity, including the number of construction and operations & maintenance jobs associated with a MW of wind energy generation. The total employment impact for 1,100 MW of wind energy generation is 2,649 jobs. This phase includes site identification and assessment, project development, project permitting, and on-site civil workers, mechanical assembly, and electrical work. Operations and maintenance of these 1,100 MW requires an additional 119 workers on an annual basis.

SOLAR ENERGY JOBS

Distributed generation installation workers per MW installed was generated from primary data collected from Michigan firms regarding typical installations (using 1,850 hours as a full-time worker equivalent) and large installation firm (multiple locations), total installation workforce divided by total annual MW installed. Both methodologies returned estimates of over 5 workers per MW; the 5.19 jobs per MW represents an average of the two figures.

Utility generation installation (construction) workers per MW installed was generated from secondary data sources for total man hours at Michigan solar utility projects. The largest project currently in operation in Michigan, the 60 MW DTE Energy Solar Farm in Lapeer, used 160,000 total man hours, or approximately 86.49 full-time equivalent

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installation workers (using 1,850 hours as a full-time worker equivalent), or 1.44 installation workers per MW.

Utility-scale installed capacity solar is currently approximately 80 MW in Michigan. The Bureau of Labor Statistics (BLS) Quarterly Census of Employment and Wages (QCEW) currently estimates <10 workers at solar electric power generation establishments (operations and maintenance positions). Secondary data sources report up to five full-time O&M workers at solar farms ranging from 60 (60 MW DTE Energy Solar Farm in Lapeer, MI) – 250 MW in the United States (various utility-scale arrays). We estimate that 18 O&M workers would be employed at a 900 MW combined utility-scale project using a straight curve from 250 MW ((900/250)*5).

ENERGY EFFICENCY JOBS

BW Research used secondary data sources to determine the number of jobs associated with 87 MW of energy efficiency measures in the State of Michigan. The American Council for an Energy-Efficient Economy's (ACEEE) findings (provided in the report "*What Will It Cost? Exploring Energy Efficiency Measure Costs over Time"*) show a $1 cost associated with 1 Watt of energy reduced by energy saving-measures. Thus, to achieve a goal of 87 MW of energy savings, a total of approximately $87 million would have to be spent on energy efficiency measures.

BW Research created four models for the following energy efficiency-related industries: residential remodelers, electrical contractors, plumbing and HVAC contractors, and commercial and Institutional Building Construction. The average results for those four models show that 87 MW of energy savings are associated with 658 direct jobs in the State of Michigan.

ECONOMIC IMPACT ANALYSIS

The economic impact analyses were developed using Emsi's input-output model, a model that traces spending and infrastructural developments through the economy. The cumulative effects of the initial spending and jobs created are measured monetarily and the results are categorized into direct, indirect, and induced effects. Direct effects show the change in the economy associated with the initial spending, or how the industry experiences the change (e.g. jobs created by the added energy capacity). Indirect effects include all the backward linkages, or the supply chain responses and local employment as a result of the initial jobs created or spending. Lastly, induced effects refer to household spending and are the consequence of workers who are responsible

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for the direct and indirect effects spending their wages in the region. Jobs in this analysis include full- and part-time wage and salaried jobs and self-employed jobs. Full- and part-time jobs are counted equally, i.e. job counts are not adjusted to full-time equivalents.

The input-output model also calculates the fiscal impact of the initial change in the economy (e.g. jobs created) by estimating the taxes on production and imports (TPI). These taxes consist of tax liabilities, such as general sales and property taxes, that are chargeable to business expenses. TPI is comprised of state and local taxes—primarily non-personal property taxes, licenses, and sales and gross receipts taxes—and Federal excise taxes on goods and services. The results of the economic analyses are presented below.

THE IMPACT OF WIND JOBS

BW Research calculated the impact of adding 2,649 construction jobs and 119 O&M jobs associated with 1,100 MW of wind energy generation. The jobs associated with the construction phase include site identification and assessment, project development, project permitting, and on-site civil workers, mechanical assembly, and electrical work. The operations jobs include the typical positions necessary to operate and maintain a wind energy plant such as technicians, engineers, and professional staff. The industries included in these two phases are engineering services and wind electric power generation. The results are provided below.

Wind Construction Jobs

A total of 9,175 direct, indirect, and induced jobs are created in the State of Michigan from adding 1,100 MW of wind energy generation. 1,517 indirect jobs are created in the supply chain as a result of the initial 2,649 wind jobs created and a significant 5,009 induced jobs are created as a result of the wages that were generated by the direct and indirect jobs and that are spent in the region's economy. The multipliers presented in Table 1 refer to the ripple effect in the economy of the initial, i.e. direct, jobs created. This means that for every direct job created, 0.57 indirect (supply chain) and 1.89 induced jobs (jobs created as a result of wage spending from the direct and indirect jobs) are created in the economy. Lastly, all this job creation and spending results in a fiscal impact of over $181 million in local and state taxes and nearly $33 million in federal taxes (

Table 2).

Table 1: Construction Jobs associated with adding 1,100MW of Wind Energy to the State of Michigan

	Direct	Indirect	Induced
Jobs	2,649	1,517	5,009
Multipliers		0.57	1.89

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Table 2: Effect on Taxes on Production and Imports

Local Taxes	State Taxes	Federal Taxes
$100,274,155	$80,927,395	$32,994,757

Wind O&M Jobs

A total of **422 O&M direct, indirect, and induced jobs** are created in the State of Michigan from adding 1,100 MW of wind energy generation. 66 indirect jobs are created in the supply chain as a result of the initial 119 wind jobs created and 237 induced jobs are created as a result of the wages that are spent in the region's economy. To note that the induced jobs are nearly twice the direct jobs, meaning that salary spending as a result of the direct and indirect jobs has a significant impact in the region's economy. Lastly, fiscal impact is a little over $9 million in local and state taxes and $1.67 million in federal taxes.

Table 3: Operations and Maintenance Jobs associated with adding 1,100MW of Wind Energy to the State of Michigan

	Direct	Indirect	Induced
Jobs	119	66	237
Multipliers		0.55	1.99

Table 4: Effect on Taxes on Production and Imports

Local Taxes	State Taxes	Federal Taxes
$5,098,804	$4,113,968	$1,672,932

THE IMPACT OF SOLAR ENERGY JOBS

The proposed added capacity for the state is 1,100 MW of solar energy, of which 200 MW are distributed generation and 900 MW are utility-scale energy generation. The impacts of this added capacity are presented below.

Impacts of 200 MW of distributed generation

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Construction

The industry included in the model to determine the construction jobs for distributed generation was electrical contractors and other wiring installation contractors. Results show that a total of **2,237 direct, indirect, and induced jobs** are created in the State of Michigan as a result of the 200 MW added capacity (Table 5). The fiscal impacts include $7.3 million in local and state taxes and $2 million in federal taxes (Table 6).

Table 5: Construction Jobs associated with 200MW of distributed generation

	Direct	Indirect	Induced
Jobs	1,038	331	868
Multipliers		0.32	0.84

Table 6: Effect on Taxes on Production and Imports

Local Taxes	State Taxes	Federal Taxes
$32,983,036	$26,654,490	$11,009,304

Impacts of 900 MW of utility-scale solar energy

The added 900 MW of utility-scale solar energy is responsible for 1,297 direct, construction jobs and 18 direct, O&M jobs. The impacts of these jobs are presented below.

Construction

The industry included in the model to determine the construction jobs for utility-scale energy generation was power and communication line and related structures construction. Results show that a total of **3,203 direct, indirect, and induced jobs** are created in the State of Michigan as a result of the 900 MW of utility-scale energy capacity (Table 7). The fiscal impacts include $11.57 million in local and state taxes and $3.24 million in federal taxes (Table 8).

Table 7: Construction Jobs associated with 900MW of utility-scale solar energy

	Direct	Indirect	Induced
Jobs	1,297	493	1,414
Multipliers		0.38	1.09

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Table 8: Effect on Taxes on Production and Imports

Local Taxes	State Taxes	Federal Taxes
$6,254,596	$5,314,380	$3,243,671

Operations and Maintenance

The industry included in the model to determine the O&M jobs for utility-scale energy generation was solar electric power generation. Results show that a total of **44 direct, indirect, and induced O&M jobs** are created in the State of Michigan as a result of the 900 MW of utility-scale energy capacity (Table 9). The fiscal impacts include $827,660 in local and state taxes and $152,789 in federal taxes (Table 10).

Table 9: O&M Jobs associated with 900MW of utility-scale solar energy

	Direct	Indirect	Induced
Jobs	18	4	22
Multipliers		0.24	1.21

Table 10: Effect on Taxes on Production and Imports

Local Taxes	State Taxes	Federal Taxes
$457,745	$369,916	$152,789

IMPACTS OF 87MW OF ENERGY EFFICIENCY IN MICHIGAN

The industries included in the model to determine the jobs associated with energy efficiency measures were residential remodelers, electrical contractors, plumbing and HVAC contractors, and commercial and institutional building construction. Based on averaged results for these four industries, a total of **1,277 direct, indirect, and induced jobs** are created in the State of Michigan as a result of the 87 MW of energy savings (Table 11). The fiscal impacts include $3.77 million in local and state taxes and $1.04 million in federal taxes (Table 12).

Table 11: Jobs associated with 87MW of energy efficiency measures

	Direct	Indirect	Induced
Jobs	658	171	448
Multipliers		0.26	0.68

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Table 12: Effect on taxes on production and imports

Local Taxes	State Taxes	Federal Taxes
$2,039,400	$1,728,029	$1,036,291

CONCLUSIONS

BW Research conducted an economic impact analysis of the direct, construction and O&M jobs associated with nearly 2,500 megawatts (MW) of renewable power plant production and efficiency savings in the State of Michigan (1,100 MW of wind energy, 1,100 MW of solar energy, and 87 MW of energy efficiency measures).

Results show that a total of **9,597 wind jobs** (9,175 construction and 422 O&M jobs), **5,485 solar jobs** (5,441 construction jobs and 44 O&M jobs), and **1,277 energy efficiency-related jobs** are created in the State of Michigan from adding 2,200 MW of renewable power plant production and 87 MW of energy savings in the state (Table 13).

Table 13: Total Job Creation of Added Energy Capacity

	Direct	Indirect	Induced	Total
Wind Construction Jobs	2,649	1,517	5,009	**9,175**
Wind O&M Jobs	119	66	237	**422**
Solar Construction Jobs	2,335	824	2,282	**5,441**
Solar O&M Jobs	18	4	22	**44**
Energy Efficiency Jobs	658	171	448	**1,277**

Regarding the ripple effects of job creation across the state, wind O&M jobs have the highest multiplier (i.e., for every direct wind O&M job created, additional 2.55 jobs are created in the economy), followed by wind construction jobs (2.46), solar O&M jobs, and solar construction jobs (Table 14). This may be driven by a multitude of factors, including the wages of the direct jobs created, the availability of resources and suppliers in the region, and the size and cost of the required energy infrastructures and technologies.

Table 14: Jobs multipliers per job type

	Indirect Jobs	Induced Jobs	Total
Wind Construction Jobs	0.57	1.89	**2.46**
Wind O&M Jobs	0.55	1.99	**2.55**
Solar Construction Jobs	0.35	0.98	**1.33**

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Solar O&M Jobs	0.22	1.22	**1.44**
Energy Efficiency Jobs	0.26	0.68	**0.94**

STATE OF MICHIGAN
MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for approval of Certificates of Necessity pursuant to MCL 460.6s, as amended, in connection with the addition of a natural gas combined cycle generating facility to its generation fleet and for related accounting and ratemaking authorizations.	))))))))	Case No. U-18419

PROOF OF SERVICE

I hereby certify that true copies of the foregoing *Direct Testimony of Kevin Lucas, Michael B. Jacobs, R. Thomas Beach, and Philip Jordan* and *Exhibits ELP-1 – ELP-63* were served by electronic mail upon the following Parties of Record, this 12th of January, 2018.

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