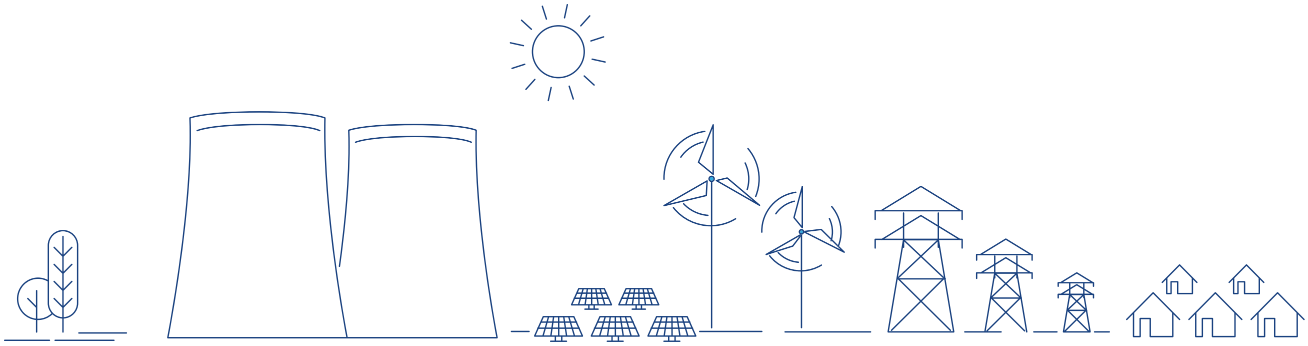
Michigan Public Service Commission
DTE Electric Company
2017 DTE Electric Integrated Resource Plan

2017 INTEGRATED RESOURCE PLAN

DTE Energy

SECTION 1

EXECUTIVE SUMMARY



1. Executive Summary

In a time of unprecedented industry change, DTE Electric (DTEE or the Company) identified that there was an opportunity to transform its generation fleet from one heavily reliant on coal, to a cleaner, more balanced mix. This aspiration was supported by the underlying challenges of an aging coal fleet and emergent environmental regulations. In response, DTEE undertook a comprehensive integrated resource planning process encompassing robust modeling and thorough risk analyses, and developed the DTEE 2017 Integrated Resource Plan (IRP).

Company Aspiration

DTEE intends to be the best-operated energy company in North America and a force for growth and prosperity in the communities in which it lives and serves. Effective implementation of the DTEE 2017 IRP is a key activity that will facilitate achieving this aspiration.

Guiding Vision

DTEE is transforming the way it supplies energy, using more natural gas, wind, and solar. As more of the generation capacity moves toward cleaner energy sources, the Company remains focused on maintaining reliability and keeping energy affordable for customers.

DTEE's efforts to cut its carbon emissions will result in a 30 percent reduction by the early 2020s, 45 percent by 2030, 75 percent by 2040, and more than 80 percent by 2050. DTEE will achieve these reductions by incorporating substantially more renewable energy, transitioning its 24/7 power sources from coal to natural gas, continuing to operate its zero-emission Fermi 2 power plant, and strengthening options for customers to save energy and reduce bills.

DTEE operates in a manner that complies with or exceeds numerous federal, state, and local environmental regulations, rules, standards, and guidelines.

Figure 1-1

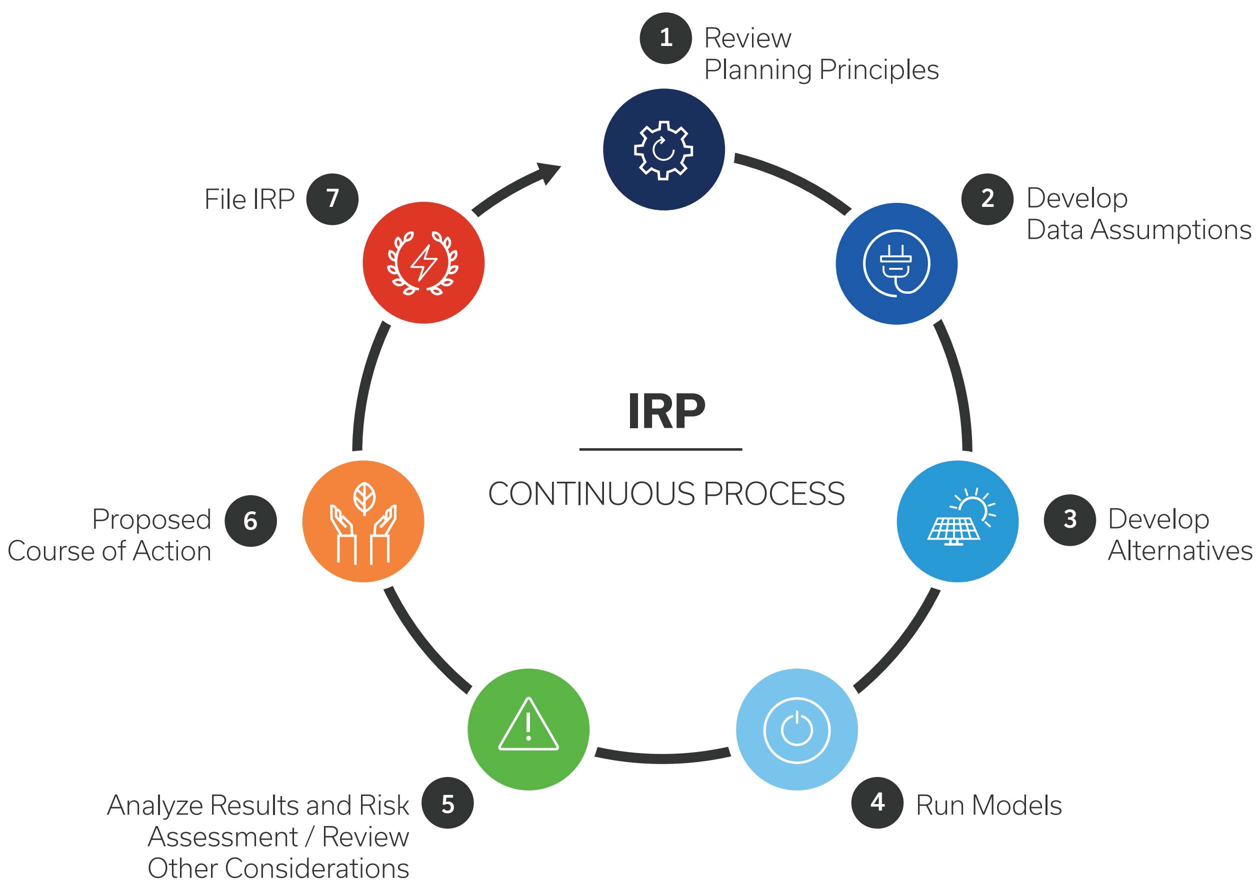
DTEE Planning Principles

RELIABILITY	Each plan analyzed was required to meet the reliability planning requirements established by MISO
AFFORDABILITY	Affordability was measured by the yearly impacts to the revenue requirement
CLEAN	Environmental sustainability and low carbon aspirations were considered as major factors in the determination of the recommended resource portfolio
FLEXIBLE AND BALANCED	The resource plan needs to be flexible, having the ability to adapt to unforeseen changes in the market. Additionally, it must have a well balanced mix of resources so that it is not heavily reliant on the market or one source of generation
COMPLIANT	All resource plans were modeled to be compliant with the 6(s) requirements as well as environmental regulations
REASONABLE RISK	The Company desires a portfolio that minimizes risks related to commodity and market pricing, fuel availability, grid reliability, capacity constraints, operations and evolving regulations

Integrated Resource Planning Process

The development of the integrated resource plan used a detailed, multi-step process that took place over more than 12 months and involved many subject matter experts both internal and external to DTEE. Figure 1-1 shows the Planning Principles used in the development of the IRP.

Figure 1-2: IRP Process



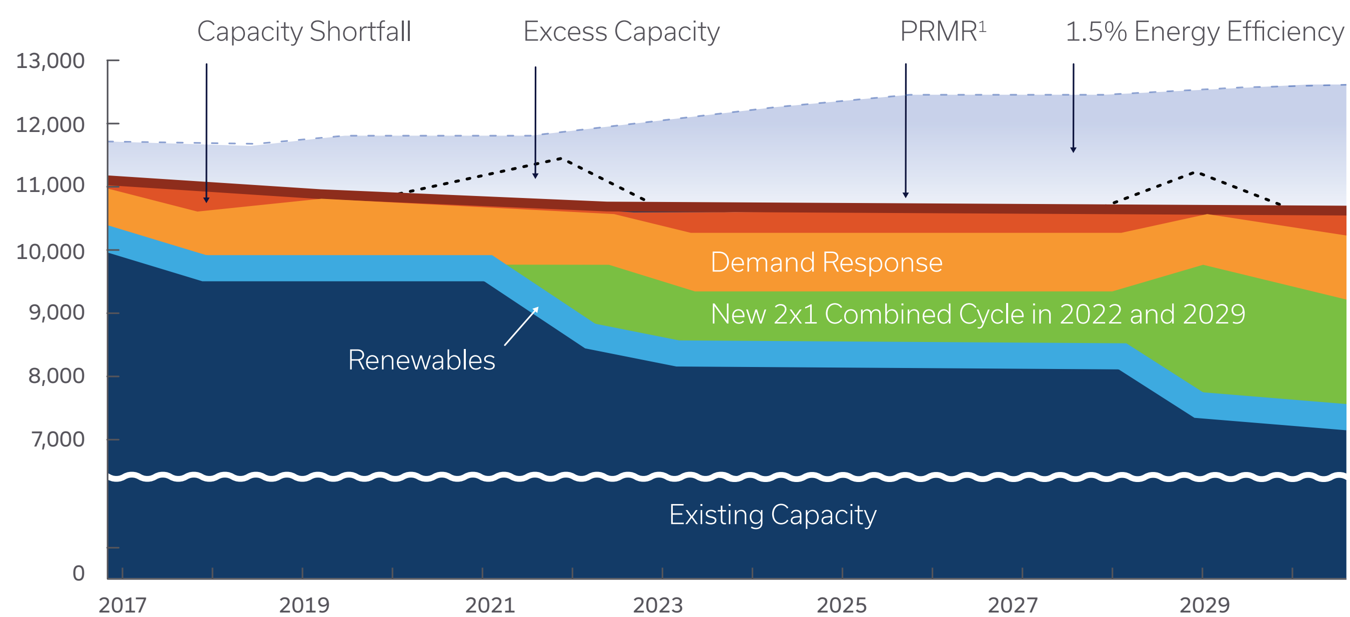
The integrated resource planning process, as shown in Figure 1-2, will continue in the future as DTEE evaluates changes in load, energy/commodity markets, regulatory rules including PA341 6t, legislative requirements, environmental impacts, and technologies that may affect the plan.

Results and Proposed Course of Action

The DTEE 2017 IRP delivers an optimal resource plan based on an in-depth analysis of supply-side and demand-side options, and an assessment of future uncertainties and risk. Through the integrated resource planning process, a significant capacity need was identified beginning in 2022 to cover demand and reserve margin requirements, predominantly as a result of the projected retirements of River Rouge, St. Clair, and Trenton Channel power plants from 2020 to 2023.

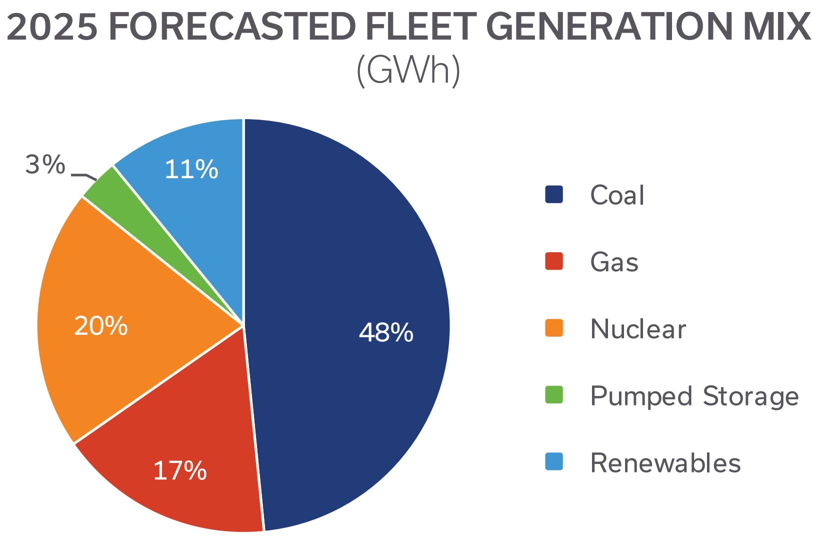
The DTEE 2017 IRP covers the years 2017 through 2040 and includes increased energy efficiency and demand response, increased renewable generation, and market purchases. To meet the capacity shortfall, the DTEE 2017 IRP selects a combined cycle gas turbine (CCGT) in 2022 and potentially again in 2029. Figure 1-3 shows the resources expected to be added and potential unit retirements for the period 2017 to 2030. Figure 1-4 shows the forecast generation mix of energy sources for 2025.

Figure 1-3: DTEE 2017 IRP (MW)



Note 1: Planning Reserve Margin Requirement

Figure 1-4



As part of the DTEE 2017 IRP, for the near term from 2017 through 2021, DTEE plans to address its capacity needs through the Midcontinent Independent System Operator, Inc. (MISO) Capacity Auction or bi-lateral contracts and demand response resources. DTEE will also continue to expand its renewable generation portfolio, continue the energy optimization (EO) program, maintain its industry-leading position in the utilization of demand response resources, and seek approval to implement this plan, including the Certificate of Necessity (CON) filing to add a CCGT.

Highlights of the Integrated Resource Plan Report:

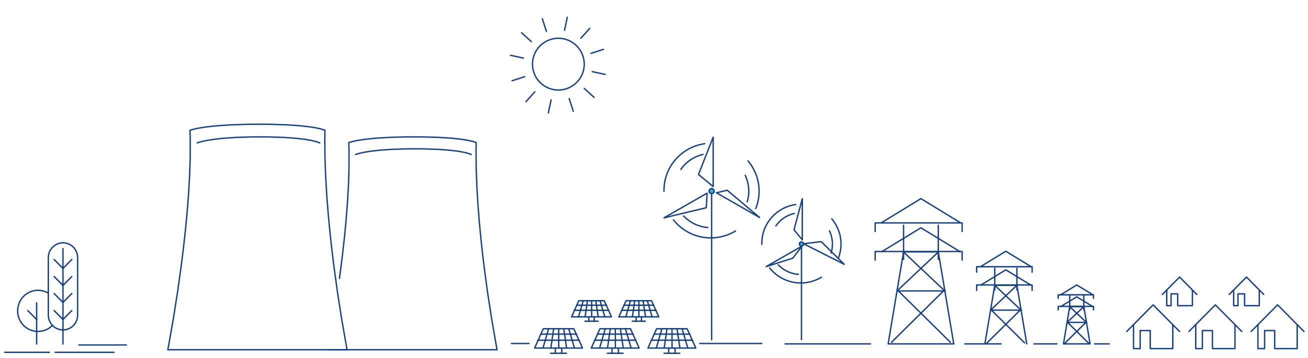
- Over the forecast period in the Reference scenario, both Bundled and Service Area sales are expected to decline annually by an average of 0.1 percent, while peak demand is expected to decline by 0.2%.
- Multiple energy efficiency programs targeting all customer groups are expected to deliver annual energy savings of 1.5 percent through 2021, exceeding the minimum energy savings requirement. Demand response programs are also expected to grow by 125 MWs.
- Through the integrated resource planning process, DTEE reviewed and evaluated risks, costs, capacity requirements, and performance parameters of supply-side power generation alternatives including natural gas, nuclear, coal-based alternatives, wind, solar, battery, and cogeneration.
- IRP modeling utilized resource cost and performance input data provided by HDR Inc., an architectural, engineering, and consulting firm, and DTEE subject matter experts. ABB, a utility technology consultant, corroborated the modeling inputs and process, incorporating IRP best practices. DTEE

modeled several scenarios to identify a resource plan that would perform well under diverse future conditions. In addition to the scenarios, DTEE applied sensitivities it designed for variables that specifically affect the Company's service territory.

- As a result of this comprehensive IRP modeling, the DTEE 2017 IRP calls for the addition of an approximate 1,100 MW combined cycle gas turbine in 2022.

SECTION 2

INTEGRATED RESOURCE PLAN OVERVIEW



2. Integrated Resource Plan Overview

The Integrated Resource Plan Overview describes the organization of this document and provides a brief description of each section. In addition, it highlights key topics discussed within the report.

2.1 Section Overview

This report is organized as follows:

Section 3 – Business Climate
Describes the business climate in which DTE Electric operates and relevant planning information.

Section 4 – Planning Process
Outlines the integrated resource planning process and the criteria that the process utilizes.

Section 5 – Load Forecast
Discusses customer electric demand and load characteristics and the Company's customer forecasting methodology.

Section 6 – Existing Resources and Operations
Describes DTEE's current generating facilities, fuel management, purchased power agreements, and demand-side management programs.

Section 7 – Load and Resource Analysis
Evaluates the balance between load and existing resources.

Section 8 – Transmission and Distribution
Describes how DTEE interfaces with the transmission system and provides an overview of the distribution planning process, criteria, guidelines, and assessment for delivering energy services to customers.

Section 9 – Environmental Stewardship and Compliance
Describes the environmental issues that affect the Company.

Section 10 – Future Alternatives
Reviews the potential resource additions that were considered in the integrated resource planning process.

Section 11 – Integrated Resource Plan Modeling
Details the integrated resource modeling process, including the inputs, scenarios, and sensitivities that were incorporated in the analysis.

Section 12 – Risk Analysis
Assesses risk to the DTEE 2017 IRP, in addition to scenarios and sensitivities, through an analytic hierarchy process (AHP) approach and stochastic analysis.

Section 13 – Proposed Course of Action
Summarizes the DTEE 2017 IRP and the short-term implementation plan.

2.2 Integrated Resource Plan Report Highlights

2.2.1 FORECASTING FUTURE CUSTOMER DEMAND

The energy forecast was developed from the bottom up utilizing a model for each customer class. Model results were added together to obtain the total Service Area sales forecast. The Electric Choice sales forecast was deducted from the Service Area sales forecast to obtain the Bundled sales forecast.

For most sectors of the forecast, electricity sales levels are related to various economic, technological, regulatory, and demographic factors that have affected them in the past. Forecast models were developed employing the appropriate regression equations. Economic variables or explanatory factors, such as motor vehicle production, steel production, and employment, were entered in the forecast models to calculate projected future sales levels.

Over the forecast period in the Reference scenario, Service Area sales and peak demand are expected to decline annually an average of 0.1 percent and 0.2 percent, respectively. Bundled sales and peak demand are also expected to decline annually an average of 0.1 percent and 0.2 percent, respectively. The growth rate for Bundled is the same as Service Area due to a steady Electric Choice sales forecast. Figures 2.2.1-1 and 2.2.1-2 show the 2016 base case forecast sales and peak demand; sales and peak demand for 2015 are temperature-normalized. The drop from 2016 to 2017 and the increase in 2018 are due to changes in auto production as facilities undergo retooling, which can move volumes significantly.

Figure 2.2.1-1

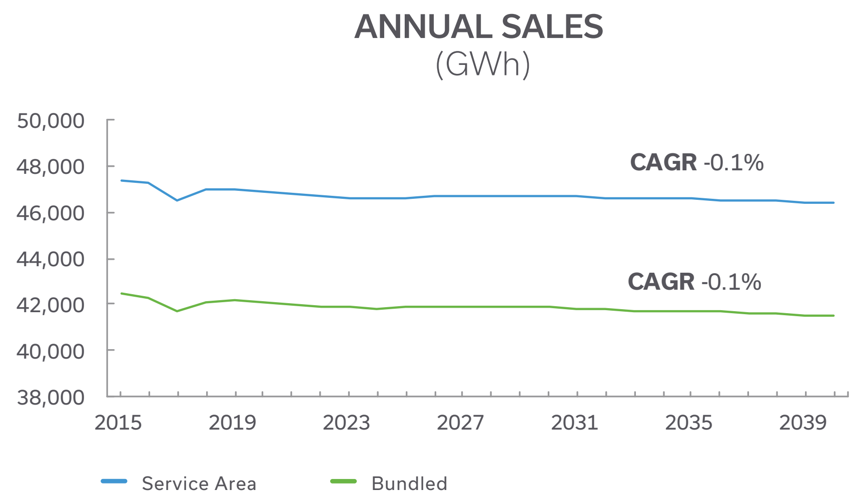
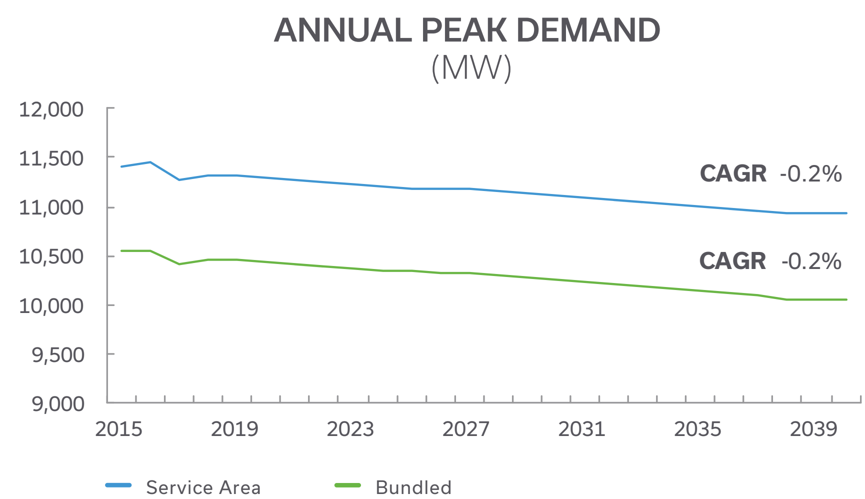


Figure 2.2.1-2



More details can be found in Section 5.

2.2.2 CURRENT SUPPLY

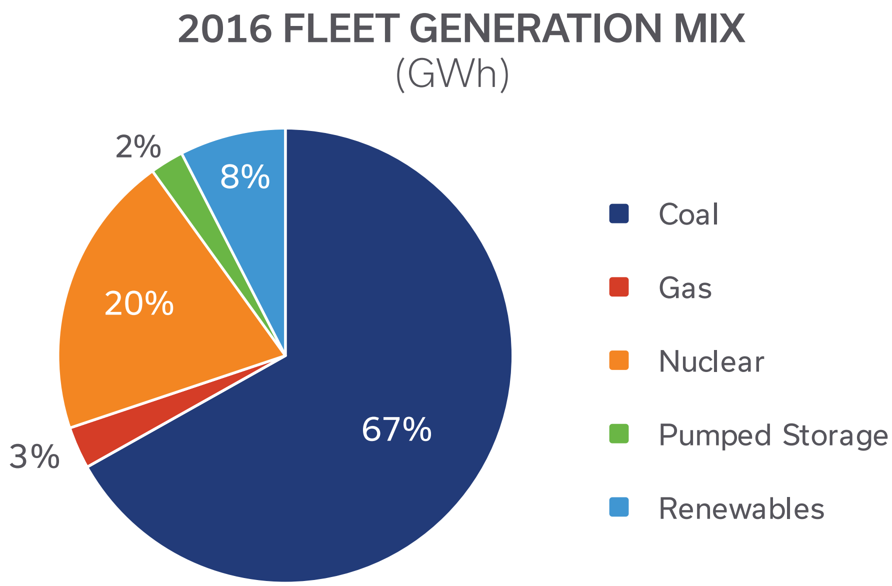
DTEE-owned generation based on summer capacity ratings is 11,602 MW, shown in Table 2.2.2-1, and based on generation mix is shown in Figure 2.2.2-1.

Table 2.2.2-1: Current Owned Generation Resources as of 2016

Rated Installed Capacity (Summer)	
Fossil Steam	7,044 MW
Peaking Plant	1,962 MW
Pumped Storage	992 MW
Total Fossil/Hydraulic System	9,998 MW
Nuclear	1,125 MW
Renewables	467 MW (451 MW wind, 16 MW solar)
Total Owned Generation	11,590 MW

In addition, DTEE has entered into various power purchase agreements (PPAs) that have been approved by the MPSC under Public Act (PA) 2/Public Utility Regulatory Policies Act of 1978 (PURPA) and the Clean, Renewable and Efficient Energy Act, also known as 2008 PA 295. Most of these PPAs are sourced with renewable generation. The Company currently has eleven PA 2/PURPA contracts and nine PA 295 contracts for both energy and capacity. The Company also receives capacity credit for customer-owned generation in the amount of 5.4 MW. The Company expects a total unforced capacity (UCAP) value of 202 MW in the 2017 planning year capacity credit associated with PPAs (including customer-owned generation).

Figure 2.2.2-1



More details can be found in Section 6.

2.2.3 RENEWABLES

DTE Electric will continue to pursue affordable renewable energy in increasing amounts in support of its carbon reduction aspiration. In 2008, Michigan's legislature passed PA 295, which created a renewable portfolio standard requiring 10 percent renewable energy by 2015. Since that time, the Company has met the requirements of the law, and currently over 95 percent of its renewable fleet consists of wind generation, which is currently the most economical renewable investment in Michigan. In December of 2016, the Michigan Legislature enacted PA 342, which amended PA 295 of 2008. The new law outlines updated requirements for renewable energy in Michigan. Under the new law, the renewable energy credit portfolio shall consist of 10 percent renewable energy credits, as were required under former section 27 of 2008 PA 295 through 2018. In 2019 and 2020, a renewable energy credit portfolio shall consist of at least 12.5 percent, and in 2021, at least 15 percent.

DTEE owns seven wind parks with a combined capacity of 451 MW within Michigan. All the parks are in the lower peninsula of the state; six are sited in the Thumb region, and one is in central Michigan.

DTEE also has entered into six wind PPAs with a combined capacity of 458 MW. Along with the energy and capacity attributes, DTEE also receives the Renewable Energy Credits (RECs) produced by these parks for use in complying with Michigan's Renewable Portfolio Standard.

DTEE has completed its Company-owned SolarCurrents pilot program, with approximately 16 MW across 28 sites throughout the electric service territory. Through the pilot, DTEE built strong and sustaining relationships with solar manufacturers, distributors, and contractors. DTEE's newest and largest 50 MW solar project became operational in 2017. This project consists of 48 MW located in Lapeer, MI and 2 MW located in Detroit, MI.

More details can be found in Section 6.

2.2.4 ENERGY EFFICIENCY HIGHLIGHTS

DTEE is firmly committed to reducing energy waste. DTEE launched its energy efficiency program in June 2009 as a result of PA 295. DTEE's energy efficiency program is designed to help reduce customers' energy use by increasing customer awareness and use of energy saving technologies, and by providing products and services, such as rebates, tips, tools, strategies, and energy efficiency education to help customers make informed energy saving decisions. DTEE has continued to build on its momentum from the 2009 launch by enhancing the scope of the existing program and adding new program options to the portfolio. DTEE's energy efficiency program has consistently exceeded savings targets and is expected to continue that trend through the future.

DTEE evaluated numerous sensitivities to determine the optimal level of energy efficiency savings for its customers. Sensitivities were modeled to evaluate drivers such as program cost, useful life, cost effectiveness, coincident peak reduction, energy savings potential, and administration efforts, providing robustness to the recommended plan.

PA 342 as passed in December 2016 establishes a minimum energy savings requirement of 1.0 percent of total annual retail electric sales per year through 2021. DTEE is planning for an energy efficiency program that delivers annual energy savings of 1.5 percent through 2021, exceeding the minimum energy savings requirement. DTEE's 2018-2019 energy efficiency plan is fully described in the Michigan Public Service Commission Case No. U-18262. The first-year energy and capacity savings for DTEE's 2017-2021 energy efficiency programs includes the forecasted amounts shown in Table 2.2.4-1.

Table 2.2.4-1: Planned First-year Energy Savings, Capacity Savings and Spend (2017-2021)

Year	Planned Energy Savings (MWh)	Planned Capacity Savings (MW)	Spend ($MM)
2017	676,997	80.7	$93
2018	706,536	74.4	$102
2019	702,666	74.8	$103
2020	702,547	75.3	$104
2021	700,016	75.6	$105

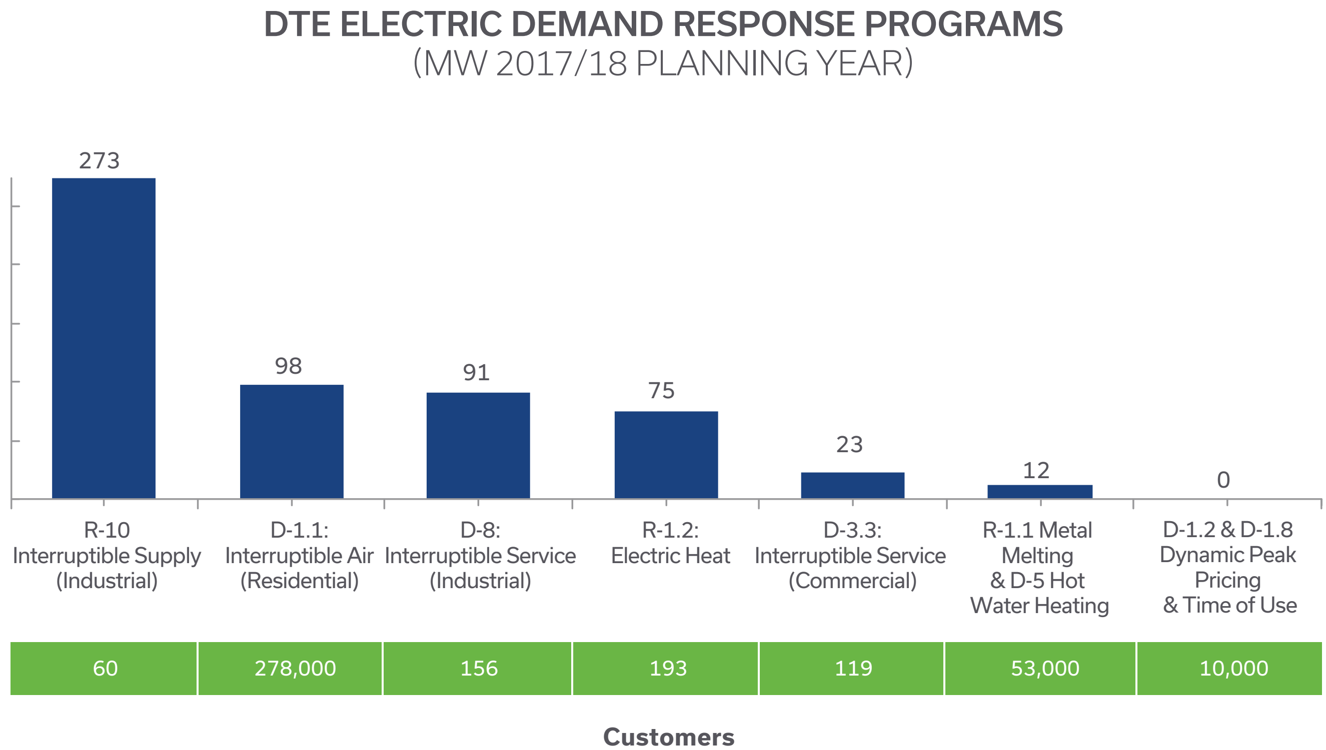
More details can be found in Section 6.

2.2.5 DEMAND RESPONSE HIGHLIGHTS

Demand response programs are targeted for peak load reduction and help reduce the need for new generation, capacity purchases, and daily market energy purchases; they also mitigate pressure on utility bills by providing benefits to customers and the DTEE system. Starting with direct load control of electric water heaters and expanding into air conditioners and other tariffs, DTEE has developed a portfolio of demand response products and services. These demand response programs are designed to help reduce customers' energy use during peak hours, providing value to customers in the form of lower bills and to the utility in lower capacity costs. DTEE has developed a top decile demand response portfolio and is recognized as a pioneer in the development of direct load control demand response programs.

With a goal and focus on growing the DR program offerings and effectiveness, DTEE is currently engaged in piloting and evaluating new demand response programs, customer effects, and program acceptance as it continues to develop and improve demand response resources. Figure 2.2.5-1 shows DTEE's current demand response programs and customer participation, totaling 572 MW for the 2017/18 planning year.

Figure 2.2.5-1



More details can be found in Section 6.

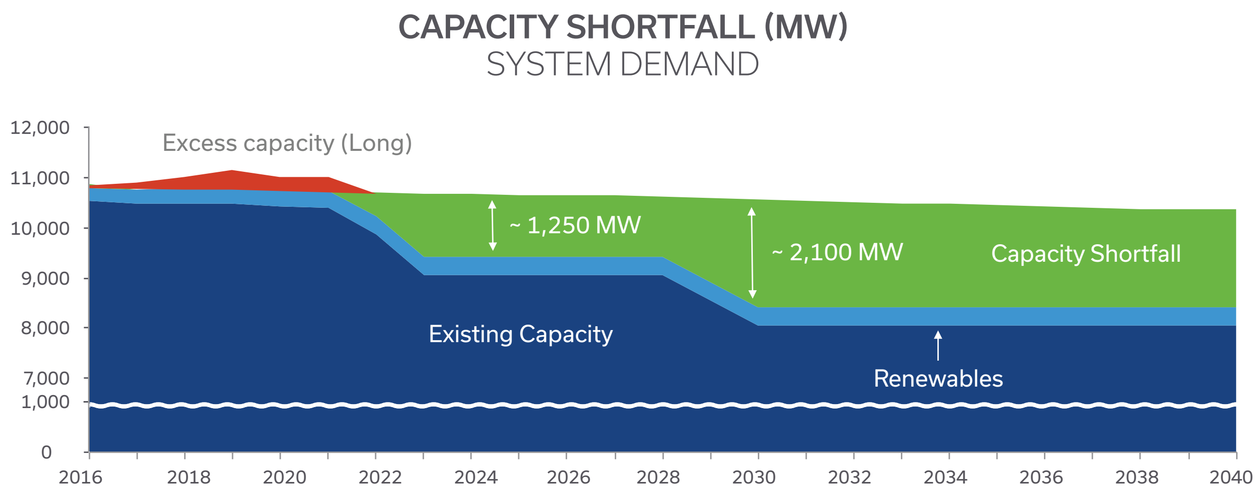
2.2.6 CAPACITY OUTLOOK

An integral part of the integrated resource planning process is to develop the Company's capacity outlook. To determine whether there is a need for additional resources, the total Planning Reserve Margin Requirement (PRMR) was compared to the total planning resources. Under the MISO Resource Adequacy construct, MISO sets an annual capacity requirement for load serving entities based on their peak demand forecast coincident with the MISO peak plus a planning reserve margin (PRM). The PRM is based on the UCAP rating of capacity resources and is referred to as "PRM_{UCAP}." In simpler terms, demand (load) must be balanced with supply (resources). If the two are unbalanced, there is either an excess of capacity and supply is greater than demand, or there is a capacity shortfall and demand is greater than supply.

In the case of DTEE's capacity outlook projection for integrated resource planning, 2022 is the first year a substantial capacity shortfall is forecast, assuming no significant changes to existing fleet resources prior to 2022. In the years after 2022, the shortfall magnitude is projected to increase, which, if not addressed with additional resources, would reach as high as 1,300 MW before 2028. The capacity shortage is a result of the projected retirements of River Rouge, St. Clair, and Trenton Channel power plants from 2020 to 2023. In 2029, there is another significant increase in the projected shortfall amount when the potential retirement of Belle River (BR) power plant occurs. Due to the load and resource analysis indicating a significant gap between DTEE's demand and resources, it is prudent to plan to cover this shortfall.

The capacity shortfall between 2022 and 2040 is shown in Figure 2.2.6-1.

Figure 2.2.6-1: 2016-2040 Capacity Outlook



More details can be found in Section 7.

2.2.7 ANALYZING FUTURE SUPPLY OPTIONS

The evaluation of generation sources for total cost, environmental benefits, reliability, effect on the electric system, and risks is an important step in the integrated resource planning process. DTEE conducted a thorough review of options, including:

- Natural gas-fired generation
- Nuclear generation
- Coal-fired generation
- Renewable generation (wind, solar)
- Storage (battery)
- Distributed generation including combined heat and power (CHP)
- Demand response
- Energy efficiency

Screening criteria include technical feasibility, commercial availability, economic attractiveness, and environmental compatibility, explained in more detail in Section 4.1.

More details on future supply options can be found in Section 10.

2.3 Integrated Resource Plan and Scenario/Sensitivity Overview

DTEE used an integrated, cost-based system planning process that accounts for electricity demand, reliability, costs, resource diversity, risk mitigation, environmental issues, and the performance variation inherent to individual energy resources. The IRP analysis relied on the Strategist model from ABB and incorporated best practices. Most of the resource cost and performance input data was supported by HDR and validated by DTEE subject matter experts; the modeling inputs and process was corroborated by ABB.

2.3.1 SCENARIOS

Scenarios help to understand the future, which is uncertain and can be difficult to predict. Therefore, when making important business decisions or large investments, it is best practice to consider how those decisions may play out under a variety of different "futures." DTEE seeks to identify a future resource plan that performs well under a diverse array of future conditions (e.g., higher fuel prices or lower CO_2 emissions). This will ensure that the resulting DTEE 2017 Integrated Resource Plan will provide optimal solutions to DTEE's future demands for electricity under a range of potential futures. A total of five scenarios were completed.

Reference: This scenario assumes that abundant low-cost supplies keep natural gas prices low. This has multiple effects: electricity market prices remain relatively low, and there are significant coal retirements due to favorable economics and pressure from continued environmental regulation of new gas units over older coal units. Due to the large number of coal retirements and new natural gas builds, the nation can comply with an assumed carbon regulation, without the need for significant carbon prices or renewable builds beyond current state mandates.

High Gas Prices: Higher natural gas marginal production costs result from higher demand, increased exports, increased costs applied to fracking operations by an increase in gas industry regulations, or a combination of the three. This leads to fewer new gas plants being built and fewer coal plant retirements. The higher levels of coal plants remaining have the effect of increased CO_2 emissions, leading to higher carbon prices, which in turn incent more renewables and natural gas to meet goals.

Low Gas Prices: Low cost natural gas supplies and continued productivity improvements keep gas prices low. This drives more coal and even some nuclear retirements due to lower power prices and reduced coal plant dispatch. CO_2 emissions plateau at a lower level, thereby eliminating the need for any carbon prices to drive down CO_2 emissions below assumed goals.

Emerging Technology: Decreasing costs and higher efficiencies for renewables (especially solar) and storage across the country leads to higher renewable penetration and lower CO_2 emissions, which would comply with the assumed carbon regulation. CO_2 prices are zero in this scenario. Electricity market prices are also lower in this scenario due to the abundance of zero dispatch cost renewable technologies.

Aggressive CO_2: This scenario assumes that carbon regulation is tightened post-2030 to keep the U.S. on a trajectory to meet 80 percent reduction by 2050. This scenario assumes that new sources are included under the CO_2 emissions cap, which differs from the assumed carbon regulation in the other scenarios. After 2030, emissions continue to decline as coal is phased out in favor of renewables and gas technologies. This scenario supports DTEE's aspirational carbon reduction goals.

2.3.2 SENSITIVITIES

Sensitivities, as compared to scenarios, are designed to test one specific uncertainty. DTEE designed its sensitivities around specific variables that affect only the Company's service territory and/or Michigan. Most sensitivities were performed on the Reference scenario, which gives a common base to compare each sensitivity with the others. For the other four scenarios, certain sensitivities were completed based upon a judgment regarding whether the varied assumption would affect the optimized portfolio.

Load: The load sensitivities included both a high growth and low growth assumption. In the high growth sensitivity, increased automotive production and data centers are prevalent. The low growth assumed that the unemployment rate is higher, population decreases, and the automotive industry reduces production.

Renewable Energy: A higher level of renewable energy was tested as a sensitivity. 1500 MW of renewables in addition to the amount included in the Reference case was used.

Energy Efficiency: Several levels of energy efficiency, both higher and lower than current DTEE goals, were tested as energy efficiency sensitivities.

Combined Cycle Capital Costs and Size: Combined cycle alternatives were tested at a 20 percent higher capital cost and in various configurations and generation capacity sizes.

Electric Choice Customer Return: Two Electric Choice sensitivities were applied to determine what would occur if 50 percent (Commercial) or 100 percent (Commercial and Industrial) choice customers returned as fully serviced DTEE customers.

More details can be found in Section 11.

2.4 Proposed Course of Action

Throughout the integrated resource planning process, DTEE evaluated numerous resource options to determine the recommended combination of supply-side, demand-side, self-build, and market resources to meet its capacity needs. DTEE performed scenario and sensitivity analyses to test the robustness and risk of the DTEE 2017 IRP related to uncertainty around environmental regulations, resource cost and performance, fuel prices, load, and other regulatory/legislative effects.

The integrated resource planning process identified that significant additional capacity is needed beginning in 2022 to cover reserve margin requirements predominantly because of the projected retirements of River Rouge, St. Clair, and Trenton Channel power plants from 2020 to 2023. The DTEE 2017 IRP reflects increased energy efficiency and demand response resources, increased renewable generation and market purchases. In addition, this plan anticipates the need for approximately 1,100 MW 2X1 CCGT in 2022 and potentially again in 2029.

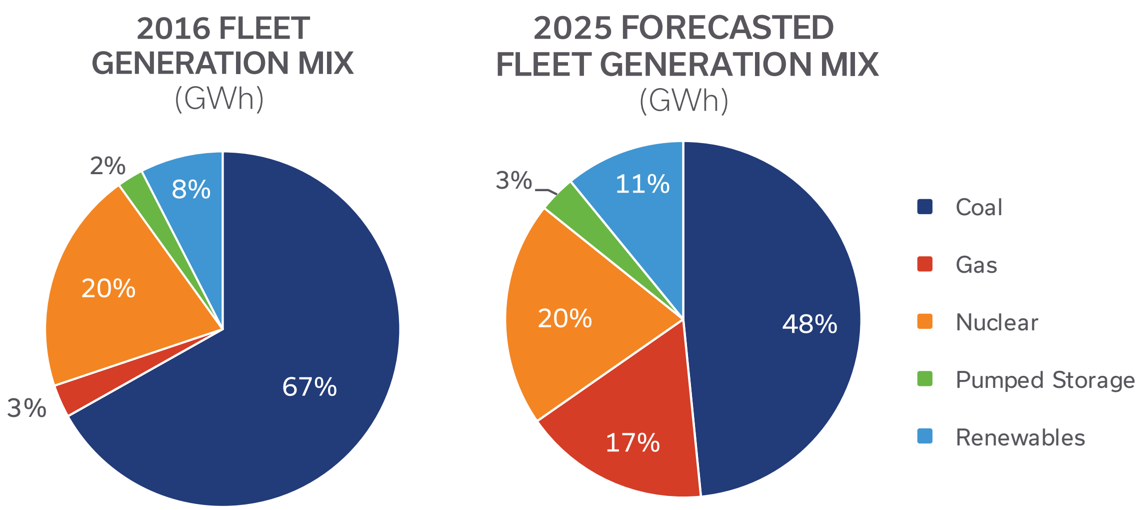
The DTEE 2017 IRP reflects generic additions to cover the shortfalls, which are described by technology and size, but the actual projects will be selected through competitive bidding and may be slightly larger or smaller in size. Table 2.4-1 outlines the resource additions included in the DTEE 2017 IRP. Figure 2.4-1 shows the forecast generation mix in 2025.

Table 2.4-1: DTEE 2017 IRP

DTEE 2017 IRP				
Category	Project	Description	MW[1] Impact	Years of implementation
Energy Efficiency Resources		Expand Program in harmony with PA 342	1.5% Sales annually	2018-2030
Demand Response Resources	Interruptible Air Conditioning	Incremental increase from 2017	125 MW[2]	2018 to 2023
Renewables	Solar Wind	Expand Renewable Portfolio to meet PA 342	30 MW[3] 107 MW[3]	2017-2025
Generic CHP	New Project	Possible CHP installation	35MW	2020
Fossil Unit Retirements	River Rouge 3 St. Clair 1-4, 6 & 7 Trenton 9 Peakers Belle River 1 & 2		-234 MW -1215 MW -430 MW -17 MW -998 MW	2020 2022, 2023 2023 2020-2023 2029-2030
Replacement CCGT	Proposed project	Addition of 2x1 Combined Cycle	1067 MW 1067 MW	2022 2029
Pumped Storage Upgrades	Ludington 1-6	Efficiency increase and capacity improvement of pumped storage	227 MW	2017-2020
Market Purchases		Used to balance short term capacity position	up to 300 MW	2022-2040

1. Impact is UCAP (i.e. MISO capacity credit)
2. 135 MW adjusted for PRMR and Transmission Losses
3. Nameplate for solar is 60 MW and wind is 686 MW

Figure 2.4-1



Having a diverse and flexible set of energy resources in DTEE's portfolio will be valuable as several important but uncertain drivers unfold, such as load forecast, natural gas price, and environmental and regulatory/legislative policy. In addition, DTEE will continue to monitor emerging technology as it develops.

The Short-Term Implementation Plan identifies the steps that DTEE will take from 2017 through 2021 to implement the DTEE 2017 IRP. In these years, DTEE will supplement its capacity needs through the MISO Capacity Auction or bi-lateral contracts and demand response resources. DTEE will also continue to:

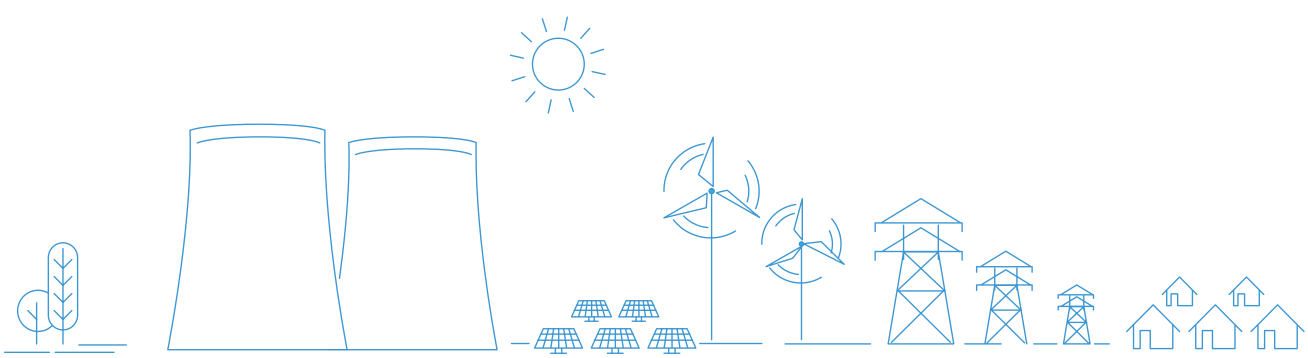
- Expand renewable generation portfolio to meet the requirements of Act No. 342 Public Acts of 2016
- Continue the EO program in harmony with the requirements of Act No. 342 Public Acts of 2016
- Offer service options for customers, including EO and voluntary renewable energy programs
- Maintain its industry leading position in the utilization of demand response resources
- Keep generation plants running safely, reliably, and cost effectively until scheduled retirements
- Complete Ludington expansion
- Seek approvals as appropriate to implement its plan, including the CON filing to add a combined cycle gas turbine

DTEE will continue to evaluate changes in load, energy/commodity markets, regulatory rules, legislative requirements, environmental impacts, and technologies that may affect the plan.

More details can be found in Section 13.

SECTION 3

BUSINESS CLIMATE



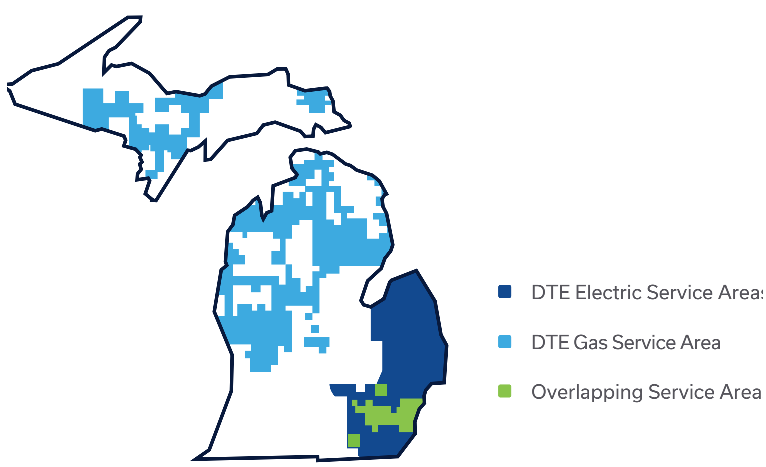
3 Business Climate

For DTEE's integrated resource planning process to be functional and reliable, it must consider the business climate in which it operates. External factors that affect the Company's market and business decisions include the local economy and industry, population shifts, environmental challenges and opportunities, regulations, standards, and legislation. As both the industry and the business climate shift continuously, DTEE must be able to respond by improving reliability, affordability, and safety.

3.1 Company Description

DTE Energy (NYSE: DTE) is a Detroit-based diversified energy company involved in the development and management of energy-related businesses and services nationwide. Its operating units include an electric utility serving 2.2 million customers in Southeastern Michigan and a natural gas utility serving 1.3 million customers in Michigan. The DTE Energy portfolio includes non-utility energy businesses focused on power and industrial projects, natural gas pipelines, gathering and storage, and energy marketing and trading.

Figure 3.1-1
DTE Energy Service Areas



As one of Michigan's leading corporate citizens, DTE Energy is a force for growth and prosperity in the 450 Michigan communities it serves in a variety of ways, including philanthropy, volunteerism, and economic progress. Information about DTE Energy is available on **www.dteenergy.com**, **twitter.com/dte_energy@DTE energy** and **facebook.com/dteenergy.**

DTE Energy has more than 10,000 employees in utility and non-utility subsidiaries involved in a wide range of energy-related businesses. DTE Electric generates, transmits and distributes electricity to 2.2 million customers in southeastern Michigan. With an 11,060 megawatt (MW) system capacity, the Company uses coal, nuclear fuel, natural gas, hydroelectric pumped storage, wind, and solar to generate its electrical output. Founded in 1903, DTEE is the largest electric utility in Michigan and one of the largest in the nation.

The electric power industry is undergoing the most dramatic change in more than 50 years due to the retirement of aging coal plants, the competitive price of natural gas, and the declining cost of renewable energy. DTEE is responding to this transformation with a focus on working safely, improving reliability, and maintaining affordability for its customers.

In 2016, DTEE's reliability was the best in more than a decade, and the rate of injuries was reduced by 40 percent compared with 2015. The average electric bill for DTEE residential customers is six percent lower than the national average, while DTEE has driven investments of $2 billion in renewable energy since 2009 and improved infrastructure by replacing 3,000 utility poles and 200 customer-serving circuits, and beginning construction on four new substations.

3.2 External Factors

In addition to industry changes, additional factors external to DTEE affect the outcome of the integrated resource planning process. These include: local economy, environmental challenges, legislation and regulations, and MISO/FERC.

3.2.1 LOCAL ECONOMY

Automotive production remains the key driver of southeast Michigan's economy. Not only is the region home to several automotive assembly plants, it also harbors a dense network of industry suppliers, contractors, and consultants. Research and development facilities similarly cluster in the area. Numerous local businesses, though not participating directly in the industry supply chain, serve the thousands who make their living in the industry.

At this time, automotive production and local plants are prospering from record sales. These high production levels can be sustained for a few more years but then production is expected to slow due to the traditional cyclical nature of the industry.

The sales forecast anticipates a short- to mid-term plateau in vehicle production and, therefore, in overall regional growth. In the longer term, production will almost certainly rise to meet the needs of a growing population. The biggest downside risk to the long-term outlook is the ongoing trend among vehicle manufacturers to site new production in Mexico. This practice has drawn criticism for its effect on American jobs and, for a host of political and economic reasons, may reverse to some degree. Another risk is the apparent low interest of the millennial generation, most often defined as those born from the early 1980s through the mid-1990s, in owning vehicles. Their low purchase rate may, however, reflect strained finances and largely reverse as they enter their prime earning years.

Over the next few years, the auto sector is positioned to lift area wage and salary employment by roughly 1.0 percent per year. For the balance of the forecast period, however, annual increases will most likely fall below 0.5 percent, being depressed by ever improving worker productivity.

Area population is expected to increase by 0.1 percent to 0.2 percent annually until the early 2030s when it reaches a peak, and then declines temporarily. This decline arises from the assumption that the limiting effect of increased worker productivity on employment will cause some current and potential Michigan residents to locate in other states.

3.2.2 ENVIRONMENTAL CHALLENGES AND OPPORTUNITIES

DTEE is transforming the way it supplies energy, using more natural gas, wind, and solar. As DTEE moves toward cleaner energy sources, it remains focused on maintaining reliability and keeping energy affordable for customers. In May 2017, DTEE announced a long-term carbon reduction initiative to reduce CO_2 emissions by 80 percent by 2050, positioning the Company as an industry leader in reducing greenhouse gases. A plan for reducing DTEE's CO_2 emissions makes business sense, ensures safe, reliable, affordable, and cleaner energy for its customers and allows the Company to implement a long-term generation transformation strategy in which more than half of the energy produced is generated from zero-emitting resources. Customers are asking for cleaner and affordable energy, and DTEE will deliver on that. DTEE's commitment to customers is to continue providing reliable, affordable energy while reducing carbon emissions and adding renewables and natural gas capacity. DTEE met with stakeholders in May, including MPSC commissioners, local, county, and state leaders, and statewide organizations, to announce this plan. DTEE's efforts to cut its carbon emissions will garner a 30 percent reduction by the early 2020s, 45 percent by 2030, 75 percent by 2040, and more than 80 percent by 2050.

Federal, state, and local environmental regulations, rules, and standards govern all DTEE's facilities; refer to Section 9 for more details. DTEE's air emissions have decreased in the last 10 years primarily due to environmental controls and fuel choices, and will continue to decrease as DTEE transforms its fleet with the addition of clean combined cycle natural gas-fired generation, substantially more renewable energy resources, increased energy efficiency, continuing use of demand response, and the retirement of coal plants. DTEE is committed to protecting clean air, water, and land resources for the health and enjoyment of future generations.

3.2.3 STATUTORY AND REGULATORY FRAMEWORK FOR IRPS

The DTEE 2017 IRP Report has been developed to support its CON application in accordance with PA 341 of 2016 (Act 341), an amendment to PA 3 of 1939, and PA 286 of 2008 (Act 286). This integrated resource plan, required by MCL 460.6s(11), is an exhibit to the CON application. This plan includes the items listed in MCL 460.6s(11) and otherwise complies with the Commission's standards developed under that section. DTEE's integrated resource planning process was designed and has been executed to meet or exceed these IRP requirements.

PA 341 includes requirements which influenced the sensitivities included in the Company's IRP. Specifically, section 6w includes requirements for alternative electric suppliers (AES) to demonstrate contractual rights to meet their capacity obligations beginning four years after the beginning of the current planning year. For alternative electric load not covered by contractual obligations of an AES, a capacity charge is required to be paid to the electric utility. Furthermore, electric providers are required to provide capacity to meet the capacity obligation for the portion of that load taking service from an alternative electric supplier in the electric provider's service territory that is covered by the capacity charge. To account for possible outcomes that could result from these requirements, the Company's IRP includes two sensitivities: one assumes that the Company must serve one half of the load currently served by AESs; and another that assumes all the load currently served by AESs becomes capacity served by DTEE.

In accordance with PA 341, the Commission drafted proposed changes to the standard CON application filing forms and instructions that were originally established in an order dated December 23, 2008 in Case No. U-15896, and on March 28, 2017 issued an order in that docket soliciting comments on those proposed changes from all interested persons. The Commission set a due date of April 14, 2017 for those comments. Several parties supplied comments which were incorporated to varying degrees, and the Commission issued an order dated May 11, 2017 with the revised CON application filing forms and instructions included in Attachment A to the Order. Certain requirements within Attachment A, section VII. A titled "New or Existing Electric Generation Facility" have bearing on what must be included in the IRP that is required to be filed with the CON application. Two examples of revised CON requirements that influence the design and/or content of an IRP beyond what must be included according to statute include:

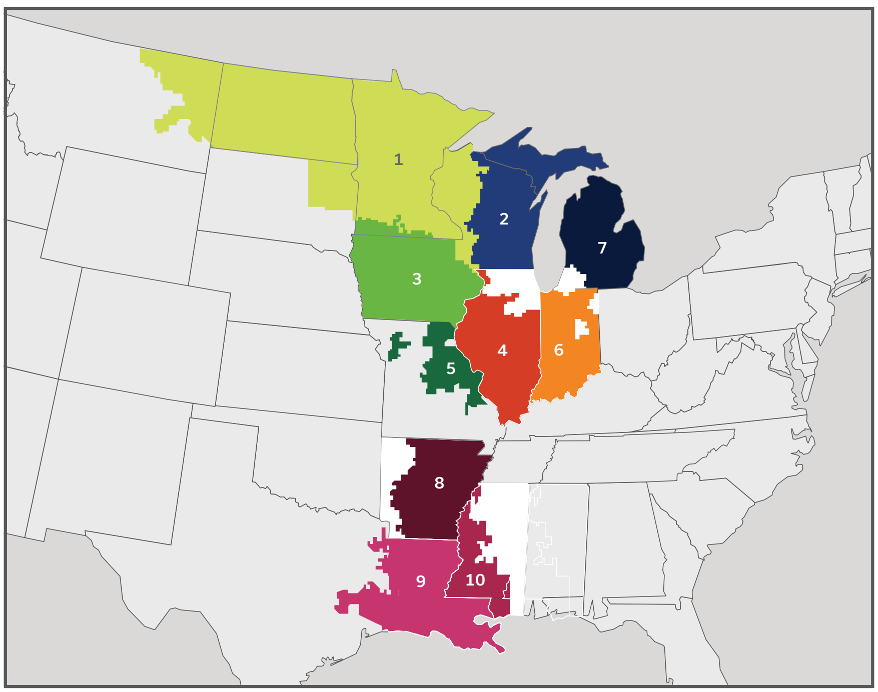
- Expected annual emissions over the life of the facility or contract and how their anticipated health effects could be eliminated or reduced using feasible and prudent alternatives; and
- Descriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility, 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. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage, and renewable energy.

DTEE believes that the long-range resource plan presented in this report fully complies with all applicable requirements and will assist in understanding the complex issues posed from the constantly changing business and regulatory environment.

3.2.4 MISO, FERC

DTEE operates within the MISO energy market as a load serving entity and generator owner. DTEE is part of MISO's Local Resource Zone 7 as seen in Figure 3.2.4-1.

Figure 3.2.4-1: Map of MISO Local Resource Zones



The Company sells generation and purchases energy from the wholesale power market in both the Day-Ahead and Real-Time energy markets, and participates in the MISO Resource Adequacy process. These markets are regulated by FERC, and DTEE (as a market participant) must comply with the FERC-approved MISO Tariff.

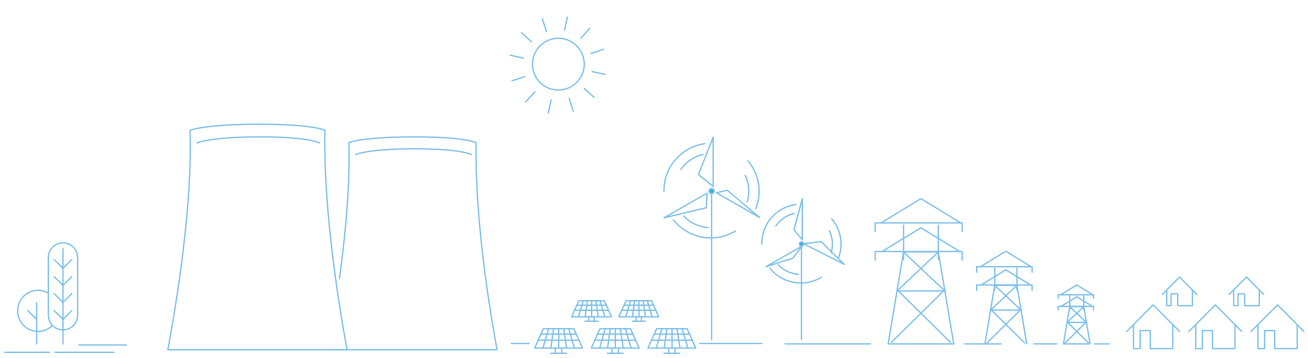
Market prices are determined on an hourly basis through Day-Ahead and Real-Time markets. The Day-Ahead market is a financially binding market that is used to schedule generation to meet a projected demand for the next operating day. The Real-Time market settles differences between Day-Ahead positions and actual operations in real time. DTEE can sell power from its generation assets and purchase power to serve its customer load in a more economical and reliable manner by participating in these markets than if the

Company operated only its own generation to serve its customer load. DTEE expects to continue to operate in the MISO markets for the foreseeable future.

MISO enables open access to transmission for new generation and performs reliability studies to determine whether transmission upgrades are needed. The allocation of costs associated with transmission upgrades are set forth by the MISO Tariff. DTEE primarily operates within the International Transmission Company (ITC) Transmission area and is subject to specific tariff language for generation interconnection. Unlike other transmission owners in MISO, ITC reimburses new generators for the interconnection costs associated with transmission upgrades.

SECTION 4

PLANNING PROCESS



4 Planning Process

The development of the integrated resource planning process used a detailed, multi-step process that took place over more than 12 months and involved many subject matter experts both internal and external to DTEE. The goal of DTEE's IRP process was to achieve a comprehensive long-term plan addressing the Company's Planning Principles—reliability, affordability, clean, flexible and balanced, compliant, and reasonable risk—while fulfilling energy and capacity demands of DTEE's full service customers.

4.1 IRP Process Introduction

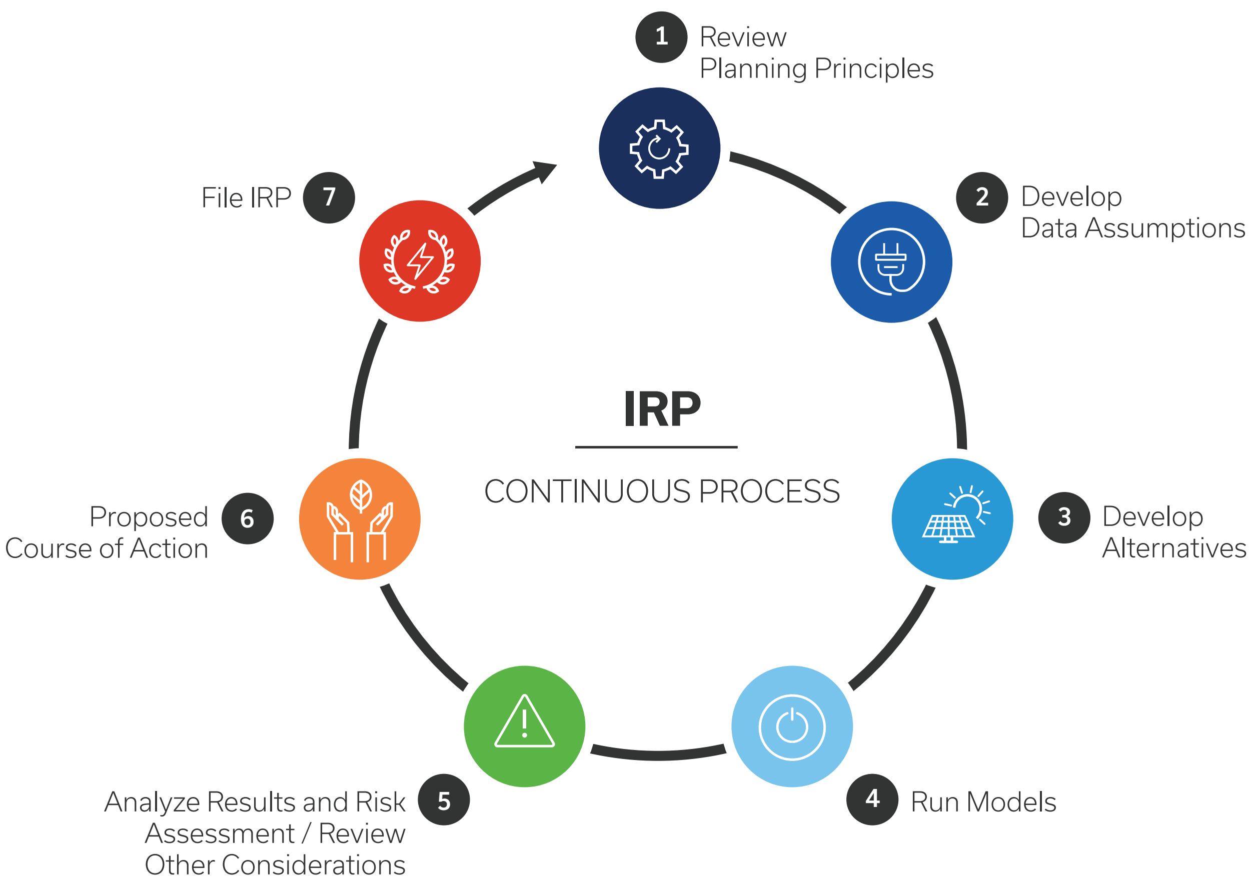
The development of the IRP was a company-wide effort with inputs collected from various business units. The IRP team led the integrated resource planning process, with the development of data and analyses coordinated and compiled into a consistent format. The IRP process relied heavily on the expertise of those business units providing information. A comprehensive list of the contributors to the IRP process is in Figure 4.1-1.

Figure 4.1-1-: IRP Input Business Units

IRP / Strategy: Generation Dispatch / Build Optimization / Financial and CO_2 Evaluation	**Renewables:** Renewable Cost Curves and Utilization Rates	**Energy Efficiency:** EE and DR Cost Curves and Load Impacts
Corporate Strategy: Long-term Market Views	COMPREHENSIVE **INTEGRATED RESOURCE PLAN**	**Corporate Energy Forecasting:** Long-term Energy and Demand Forecasts
FosGen: Existing Plant Capital and O&M projections / New Gas Plant O&M		**MEP:** New Gas Plant Capital / Existing Plant Major Modification Cost
Fuel Supply: Delivered Fuel Prices	**EM&R:** Environmental Compliance Requirements including Clean Energy Plan	**Regulatory & Government Affairs:** Regulatory Requirements and Policy Assessments

The process to develop the integrated resource plan was extensive, requiring over a year of preparation. Because a formal IRP report had not been published since 1994, a new process was established based on the requirements set forth in 2008 PA 286. The IRP is also consistent with the requirements in PA 341 section 6s. The Company's IRP process contains seven steps designed to ensure the completion of a comprehensive plan; see Figure 4.1-2. Because assumptions and environmental and regulatory factors change, the integrated resource planning process must be continuous.

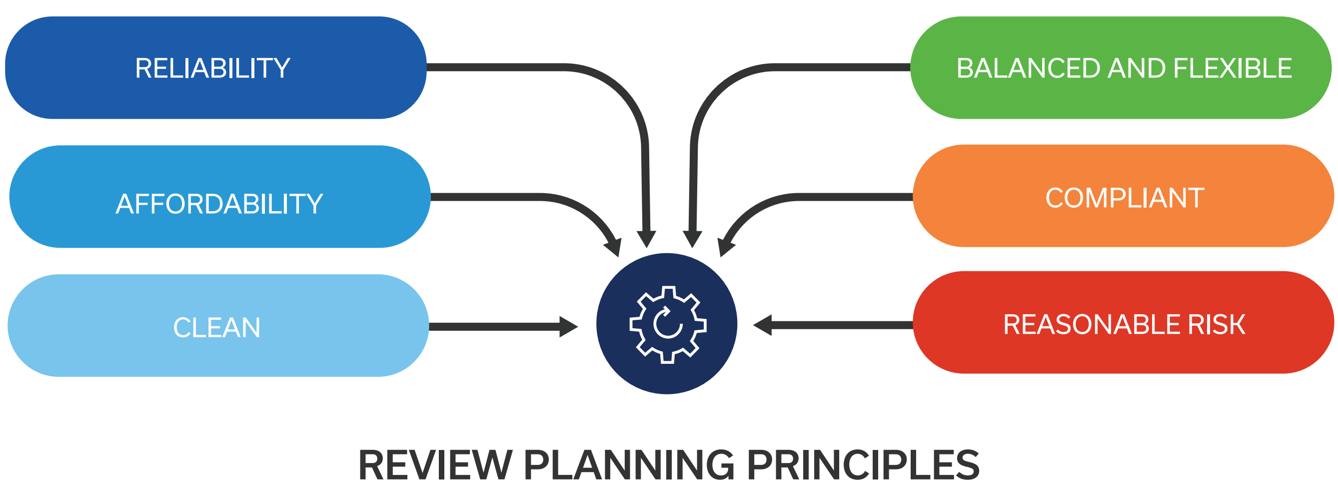
Figure 4.1-2: IRP Continuous Process



4.2 Step 1: Review Planning Principles

The first step in the IRP process was to review the Company's planning policies, and internal and external factors that have the potential to impact the Company's plans. The IRP process needed to address known specific regulatory requirements, as well as other factors that were less certain. The first planning principle explored was reliability, each plan analyzed must meet the reliability planning requirements established by MISO. The next principle was affordability, the plan must be measured by the yearly effects on the revenue requirements. Clean was another principle, environmental sustainability and low carbon aspirations were major factors in the determination of the DTEE 2017 IRP. The plan must also be flexible and balanced, having the ability to adapt to unforeseen changes in the market. Additionally, it must have a well-balanced mix of resources so that it is not heavily reliant on the market or one source of generation. Another principle was compliant, all resource plans were modeled to be compliant with the PA 341 section 6s requirements, as well as environmental regulations. Finally, the plan must maintain reasonable risk, the Company desires a portfolio that minimizes risks related to commodity pricing, fuel availability, grid reliability, capacity constraints, operations, and regulations. Figure 4.2-1 displays the various considerations within the Planning Principles.

Figure 4.2-1: Corporate Planning Policy



4.3 Step 2: Develop Data Assumptions

After reviewing the Planning Principles, the next step was to develop a broad set of scenarios and sensitivities, with detailed assumptions supporting them. Typical for any integrated resource planning process, a robust set of scenarios and sensitivities was employed to aid in selection of the DTEE 2017 Integrated Resource Plan. Scenarios are made up of driving forces that shape and define different paths to the future. They contain key uncertainties that are critical components to help construct and differentiate among scenarios. These are generally broad market assumptions that affect the entire country, such as commodity prices, technology costs, national load growth, and environmental regulations, to name a few.

Sensitivities, considered smaller changes from a modeling perspective, are Company-specific variables that affect only the DTEE service territory and/or Michigan. Examples of sensitivities are changes in load, energy efficiency, and renewable targets. The purpose of both scenarios and sensitivities was to test the base resource plan (explained further in Section 11 Integrated Resource Plan Modeling) under changing assumptions and to develop the most reasonable and prudent plan. Sensitivities were chosen that would potentially cause the most disruption to the base resource plan to test whether the plan would still be reasonable under changing conditions. The most reasonable and prudent long-term plan can be considered the best decision for the customer, not only on a cost basis but also in alignment with the Planning Principles—reliability, affordability, clean, flexible and balanced, compliant, and reasonable risk.

Once the market assumptions were developed, both DTEE-specific energy and capacity demand forecasts were developed. The load and capacity demand forecasts were then compared to DTEE's existing supply resources, accounting for planned retirements, to determine whether there was a need for additional resources. The comparison would identify any gap between supply and demand during the 2016 to 2040 forecast period. The comparison projected a capacity need in both magnitude and timing.

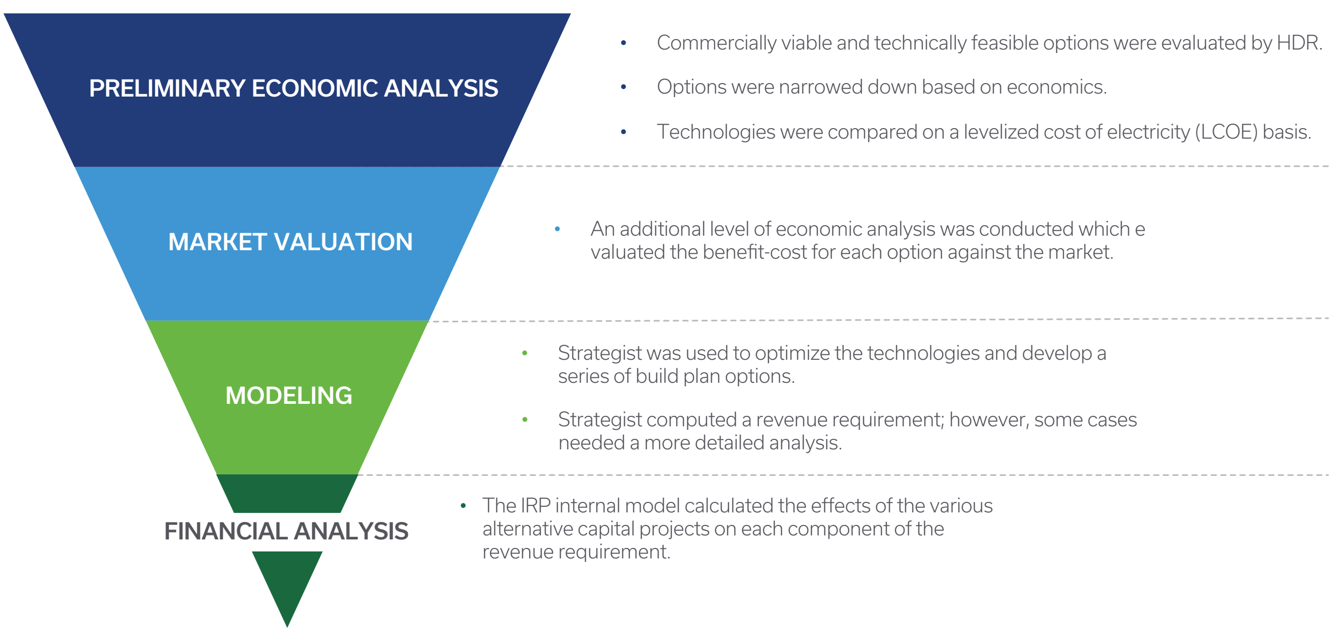
4.4 Step 3: Develop Alternatives

Because the IRP process determined there would be a need for energy and capacity additions, the next step was to select the resource alternatives available for consideration. HDR, Inc., an external consultant, was utilized to obtain information regarding potential resource options. HDR provided an engineering evaluation study summarizing costs and performance parameters of supply-side power generation alternatives. For renewable options and demand-side management alternatives, internal subject matter experts were utilized. To ensure the robustness of the IRP modeling, an extensive list of alternatives was evaluated, including the following: gas-fired technologies, such as combustion turbines and combined cycles; renewable technologies, such as wind and solar; and demand-side management expansions of demand response and energy efficiency programs beyond what was specified in the Michigan legislature[1].

4.5 Step 4: Run Models

DTEE used various modeling methodologies to determine the most viable technologies for the IRP modeling. The evaluations ranged from simplistic economic screenings to increasingly complex analyses. The methods for screening and evaluating technology options are shown in Figure 4.5-1.

Figure 4.5-1: IRP Modeling Process



[1] Michigan 2008 PA 295 and 2016 PA 342.

The first level of modeling was a preliminary economic analysis consisting of a levelized cost of electricity comparison (LCOE) between similar technologies. The $/MWh value was computed for each technology option for capital, fuel, and operation and maintenance costs. The initial screening was concluded with the LCOE, and the options that were the least economical in terms of the highest $/MWhs were eliminated. At the next level of screening, the remaining technology options were modeled with Strategist, and a market valuation or benefit-cost analysis was performed.

The market valuation was used to screen out options that were shown to be less cost effective. The analysis computed a benefit-cost ratio that compared the financial benefits realized by investing in a technology to the costs of executing the project. The ratio was calculated by dividing the present value benefits by the present value costs; the higher the benefit-cost ratio, the better the investment. All the technologies were ranked by the benefit-cost ratio, and the least cost-effective options were eliminated.

Following the market valuation, for the modeling step, the Strategist PROVIEW™ module was used with the associated costs of the alternative options and existing resource operational data. PROVIEW generated the least cost resource plan options under the various scenarios and sensitivities to fill the need resulting from future coal retirements. PROVIEW provided a multitude of resource plans and ranked the options in order of least cost determined by present value utility cost. The results of PROVIEW were thoroughly analyzed to identify a base resource plan based on not only economics but also what was the best option for customers based on the Planning Principles. The Company's objective is to provide a reliable, affordable, clean, flexible and balanced, compliant, and reasonable risk portfolio. Taking this into consideration, a base resource plan was selected. The base resource plan remained the same in all scenarios and was used to compare sensitivities. The base resource plan was identified simply to have a common comparison across all scenarios and sensitivities. Once the comparisons were completed and analyzed, the lowest cost resource plan for each scenario or sensitivity was selected for further analysis (i.e., selected resource plans). Ultimately, DTEE selected one resource plan that was the most reasonable and prudent as the DTEE 2017 IRP (described in Section 2.4).

To get a deeper understanding of how a particular resource plan would affect customer costs, the resource plans were then modeled with a more detailed program, PROMOD. This software tool performs a more granular simulation of the forecasted operations by running hourly dispatch, as opposed to the typical week that Strategist executes. Following the more detailed modeling, the resulting production costs, such as operation and maintenance, fuel, energy and capacity, of the resource alternatives were then loaded into an internal revenue requirement model.

The purposes of the internal revenue requirement model were to better assess the financial effects to the customer, using the more refined PROMOD data, and to corroborate Strategist results; two separate processes which derive the same conclusion function as verification. The internal revenue requirement model represented the Company's financial structure and treatment of capital investments. To test uncertainty in the future assumptions, the selected resource plans that varied the most from the base resource plan were further tested. For each selected resource plan put through the internal revenue model, an annual revenue requirement was computed for years 2016 through 2040. Each selected resource plan was then compared to the base resource plan and a variance or delta was created between the cases. Then the annual stream of delta revenue requirements was discounted back to 2016 dollars to derive a delta net present value revenue requirement. A positive delta indicated that the base resource plan was a more expensive plan, and a negative delta indicated the base resource plan was more cost effective.

4.6 Step 5: Analyze Results, Review Other Considerations and Risk Assessment

Although costs are a fundamental consideration, other factors are also important. Reliability, environmental impacts, flexibility, and a balanced portfolio are planning principles developed to manage the potential risks of the ever-changing market and regulatory conditions. After the DTEE 2017 IRP was selected, a risk analysis was conducted to ensure that the plan was prudent considering these factors. DTEE intends to ensure risk is minimized for both customers and other stakeholders across a broad range of changing assumptions; therefore, risk assessment is an essential part of the IRP process. Over time, commodity markets and environmental and regulatory conditions may change from what was initially forecast. The DTEE 2017 IRP is flexible enough to accommodate these changes as they occur.

4.7 Step 6: Propose Course of Action

The DTEE 2017 IRP was developed by comparing the results of the scenario and sensitivity analysis along with the risk assessment to ensure that the optimal plan will be suitable over a wide range of uncertainties. The DTEE 2017 IRP in the early 2020s selected a CCGT to fill the significant energy and capacity gap caused by the retirement of River Rouge (234 MW UCAP), St. Clair (1,214 MW UCAP), and Trenton Channel (430 MW UCAP) power plants in 2020, 2022, and 2023. Due to the fluctuation and/or uncertainty of market conditions over the longer term (post 2022), the plan will continue to be re-evaluated as changes occur. The DTEE 2017 IRP represents a balance between demand-side and supply-side options while providing favorable economic outcomes for customers. By replacing the retiring coal generation with the most prudent technologies or resources, the projected load requirements and clean energy goals can be met in an optimal manner.

4.8 Step 7: File IRP

To support the DTEE 2017 IRP, all the analysis is summarized in an official Integrated Resource Plan Report, which is this document. The IRP Report is needed to justify the selected long-term resource plan and to document the due diligence of the Company in evaluating all possible options available and selecting the most reasonable and prudent long-term resource plan. The final step in the process consists of filing the IRP. If the IRP process identifies a need to add generation, the IRP will be filed with a Certificate of Necessity (CON) application.

4.9 Stakeholder Engagement

4.9.1 STAKEHOLDER COMMUNICATIONS

As part of the IRP process, DTEE conducted meetings with MPSC staff to communicate its process and progress on a plan to add generation, and to answer questions regarding the process. DTEE has plans in place to communicate and has communicated with stakeholders, such as local, county, state, and federal leaders, business organizations, and environmental organizations, to discuss its future plans. DTEE plans to facilitate stakeholder discussions and communications through July 2017 and beyond.

As part of its normal business practice, DTEE has engaged interested stakeholders on an ongoing basis as plans were developed in the transformation of its fleet from coal-fired generating units to a mix of cleaner energy. In June 2016, the Company announced plans to retire three of its five coal-fired plants in Michigan—River Rouge, St. Clair, and Trenton Channel—between 2020 and 2023, and to replace that capacity with a mix of newer, more efficient, and cleaner sources of energy generation, such as wind, solar, and natural gas. Additionally, DTEE will continue its energy optimization and demand response programs as part of the Company's strategy to provide customers with safe, clean, reliable, and affordable power. DTEE reached out to local leaders, regulators, environmental agencies, suppliers, and customers to communicate the plant closures and to answer any questions.

As its coal-fired power plants are retired, DTEE recognizes that there will be economic effects for neighboring communities and has met with local leaders on several occasions. DTEE leaders met with affected communities to discuss the plant retirements and how DTEE will work with the local communities in obtaining and matching grants. In 2016, DTEE matched two $50,000 economic development grants awarded to St. Clair County and the City of Harbor Beach from the Economic Development Administration, for a total of $100,000 to perform economic studies. In March 2017, DTEE matched two $50,000 economic development grants awarded to the City of River Rouge and the

City of Trenton from the Economic Development Administration, for a total of $100,000. These funds were provided to assess and create an economic development strategy for the downriver region. DTEE's efforts in assisting communities with grants is in addition to the community-wide events the Company continues to support annually. DTEE will continue to work with these communities in the future to identify additional grant opportunities and to communicate progress on future plant retirements.

Related to renewable energy and energy efficiency, customers and stakeholders are engaged to obtain feedback on new and existing projects and programs. For example, the Renewable Energy program works with its landowners throughout the process from project initiation through construction to obtain feedback on its process and to answer questions. DTEE hosts prospective land owner meetings to educate local land owners on potential future wind energy development in their regions, as well as meetings for participating landowners to provide project updates, listen to concerns and suggestions, and respond accordingly. DTEE also participates in township association meetings to share future plans, request project approvals, respond to concerns, and listen to stakeholder feedback. Its energy efficiency group's approach to stakeholder engagement includes benchmarking with top performers within the Midwest utility peer group, conducting comprehensive customer research, and collecting feedback on the customer experience. DTEE conducts pre- and post-research through quantitative and qualitative focus groups, customer surveys, and one-on-one interviews to gain insight on many aspects of its program offerings and to apply this research to shape the customer experience. Studies, research, and customer experiences help DTEE to identify best practices, develop improvements, and learn how to apply enhancements across all energy efficiency programs.

4.9.2 WORKING COLLABORATIVELY

In support and preparation for Michigan's energy transformation, DTEE actively participated in negotiations that resulted in the passage of energy legislation. The 2016 energy legislation passed by the Michigan legislature was the product of significant stakeholder engagement, including DTEE, dating back to three years before the passage of the policy. In 2013, Governor Rick Snyder led the initiative to prepare for Michigan's energy transformation through the "Readying Michigan to Make Good Energy Decisions" process. This comprehensive initiative asked stakeholders to respond to and comment on topics including renewable energy, energy efficiency, generation planning, generation diversity, and the Retail Open Access service.

Stakeholder engagement in the legislature was formalized through the Senate Energy and Technology Committee Chairman Mike Nofs' energy policy stakeholder workgroups, held from 2013 to 2014. This engagement continued into Chairman Mike Nofs' and Vice-Chairman John Proos' two-year energy policy development process that concluded in December, and included testimony hearings, negotiations, and public forums. At the same time, House Energy Policy Committee Chairman Aric Nesbitt hosted multiple hearings in which all stakeholders were invited to share their positions. DTEE actively listened, participated, and supported the stakeholder engagement and intervention processes established in the 2016 energy package.

DTEE is currently participating in eight implementation work groups in support of the integrated resource plan statewide parameter setting and modeling, which is part of the new energy law. The implementation workgroups DTEE is participating in include Energy Waste Reduction, Demand Response, Environmental Policy, Renewables and PURPA, Other Market Options, Filing Requirements, Transmission, Forecasting, Fuel Prices, and Reliability. DTEE will be working collaboratively with the MPSC, Michigan Agency for Energy, and the Department of Environmental Quality (DEQ) in setting modeling parameters and assumptions to use in future integrated resource planning processes.

On energy optimization, DTEE has participated in the Energy Waste Reduction (EWR) Collaborative (formerly known as the Energy Efficiency Collaborative) since 2009. Through this collaborative, DTEE works with energy efficiency stakeholders in Michigan, including the Michigan Public Service Commission (MPSC), investor owned utilities, municipalities and co-ops, implementation contractors, and evaluation contractors to make recommendations for improving energy optimization programs for all providers. As part of the EWR collaborative, DTEE also works with stakeholders to provide support for program evaluations and improvements to energy waste reduction programs, to update and refine the Michigan Energy Measures Database (MEMD), and to promote economic development and job creation in Michigan by connecting stakeholders.

Within Demand Response, DTEE participated with the MPSC in providing input into the September 2016 Demand Response Potential Study Feasibility Report. The MPSC coordinated with the Michigan Agency for Energy, regulated utilities, and other stakeholders to examine the feasibility of and options for conducting a demand response study in Michigan. As part of the collaborative process, it was determined that a state-wide demand response potential study is feasible as part of the path to a reliable and affordable energy future.

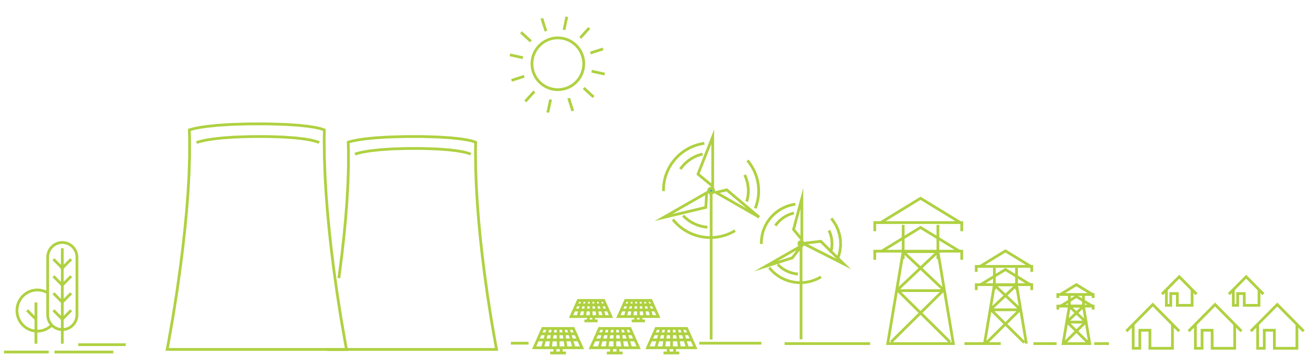
4.9.3 MAINTAINING RELATIONSHIPS

Maintaining relationships with DTEE's stakeholders is a key part of achieving the Company's aspiration to be a force for growth in the communities in which it lives and serves. DTE Energy's stakeholder engagement process involves outreach to people and organizations who want input into its process and who may be affected by the decisions DTE makes. DTE believes everyone benefits from the exchange of information and open dialogue. DTE maintains a Community Advisory Council, which involves a rotating group of community members. The Community Advisory Council is a partnership that allows DTE to gain insight into local perceptions of DTE Energy and provides an opportunity to improve its relationship with the community and to develop programs that better serve the needs of its customers.

DTE's Regional Relations team proactively manages relationships with elected and appointed officials, and in partnership with Public Affairs, works with key community stakeholder organizations and nonprofits. The Regional Relations team represents DTE through membership and interaction with 45 Chambers of Commerce across Michigan. In addition, DTE executive leaders contribute their expertise and time to the community by serving in 70 board positions for nonprofit organizations throughout DTE's service territory. Refer to Appendix A for a list of stakeholder groups, types of engagement, and topics raised as examples of how DTE continues to engage and work with its stakeholders.

SECTION 5

LOAD FORECAST



5 Load Forecast

An accurate load forecast for the planning period is a key input to the IRP. DTEE developed its load forecast by analyzing historical data to identify the statistically significant factors in energy sales in each customer class. The resulting models included economic variables and projected increases in energy efficiency to forecast annual DTEE Service Area and Bundled sales and peak demand. For both Service Area and Bundled in the Reference scenario, sales and peak demand are expected to decline annually an average of 0.1 percent and 0.2 percent, respectively. To manage future uncertainties, both high and low load forecast sensitivities were developed and compared with the Reference scenario. The accuracy of DTEE's sales and peak demand forecasting compares favorably to a third-party benchmarking study conducted in 2016.

5.1 Methodology

5.1.1 ENERGY FORECAST OVERVIEW

The energy forecast was developed from the bottom up, utilizing a model for each customer class. The results of the models were added together to obtain the total Service Area sales forecast. The Electric Choice sales forecast was subtracted from the Service Area sales forecast to obtain the Bundled sales forecast. The forecasts used in the Reference scenario, high load and low load sensitivities were developed in 2016 for IRP model runs at that time.

For most sectors of the forecast, electricity sales levels are related to various economic, technological, regulatory and demographic factors that have affected them in the past. The procedure began with the assembly of historical data relating to the various sectors of the forecast. This data was examined, and the factors that were statistically significant in explaining electric sales were identified using regression techniques. Forecast models were developed employing the appropriate regression equations.

Forecasts of economic variables (explanatory factors), such as motor vehicle production, steel production, employment and other economic indicators were entered in the forecast models to calculate projected future sales levels.

Figures 5.1.1-1 and 5.1.1-2 show the percentage of Service Area sales and peak demand for each customer class for 2017.

Figure 5.1.1-1

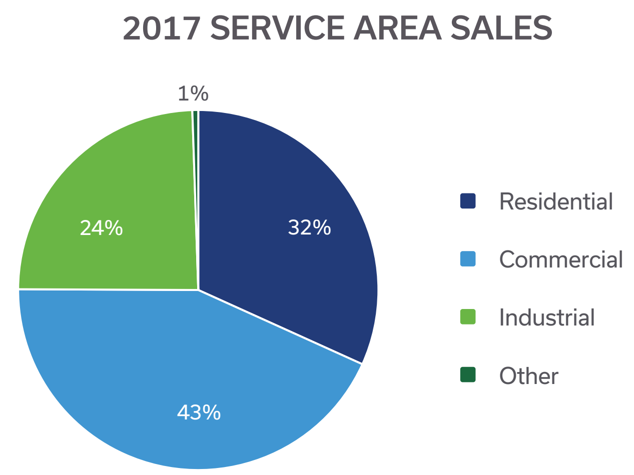
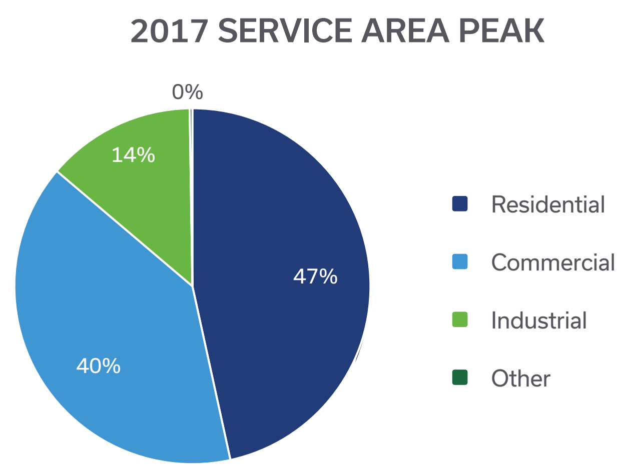


Figure 5.1.1-2



Residential

Electricity sales in the Residential class were forecast by an end-use method including 39 different appliances or appliance groups. For each forecast year, three separate items were forecast: number of residential customers; saturations of major appliances; and average electricity use per appliance. For each appliance, the product of these three forecast values yields the annual electricity sales. The total for all appliances is the total annual Residential class electricity sales.

The number of residential customers were forecast using the annual percentage change in households. This percentage change each year was applied to the prior year's customer count to obtain the forecast of customers for that year.

The Company conducts a residential appliance saturation survey, usually every other year. The most recent survey used in this forecast was conducted in early 2015. The survey was sent to a representative sample of DTE Electric's residential customers. Some of the questions relate to whether the customer has certain appliances and whether the appliances were replaced in the last two years. The responses help the Company to understand the penetration of appliances in DTEE's Service Area. These insights were then applied to the residential forecast model.

The federal government has enacted energy efficiency standards for many appliances. The end-use approach incorporates projected increases in energy efficiency of the various appliances into the Residential class electricity sales. The Company uses federal efficiency standards to determine the decrease in use per appliance. As most customers do not buy a new appliance just because a more energy efficient one becomes available, the Company phases in the decrease in energy usage, which over time drives down residential customer electricity usage.

Commercial

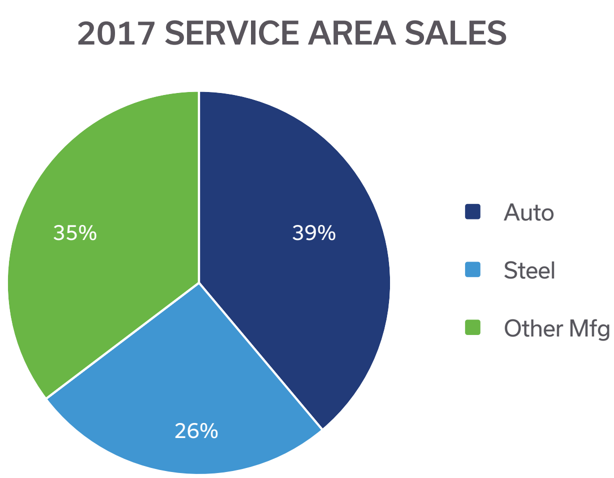
Sales for most sectors of the Commercial class were forecast using regression models. Explanatory variables included county level employment, local automotive production and population. Other markets, such as agricultural supply, farming and apartments, were forecast with time trend models and were combined with the previous regression models to obtain total Commercial class electricity sales. In addition, two universities are planning to build co-generation facilities which will reduce sales by over 177 GWh annually by 2020. Figure 5.1.1-3 shows the sectors of the Commercial class and their respective percentage of the total commercial sales volumes in 2017. Commercial Secondary and Primary rate class sales were obtained using historical allocations for each market, which were then summed to get total Commercial Secondary and Primary sales, resulting in an approximately 55 percent/45 percent split.

Figure 5.1.1-3

Industrial

Industrial class sales consist of three large sub-classes: automotive, primary metals (steel), and other manufacturing sales. The relative size of the sub-classes is shown in Figure 5.1.1-4.

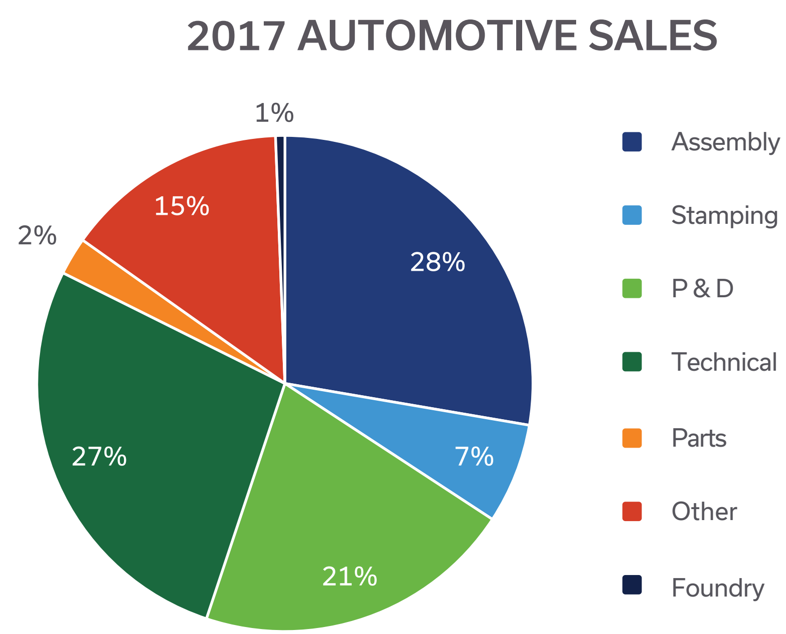
Figure 5.1.1-4



Auto

For the development of the Industrial class forecast, the automotive sector was disaggregated into seven groups of automotive facilities, as shown in Figure 5.1.1-5: assembly plants, stamping plants, powertrain/drivetrain plants (P&D), research and administrative facilities (technical), other parts plants and parts suppliers, foundries, and other automotive plants. Electricity sales for most of these groups were forecast using regression-based models with automotive production as the primary explanatory variable. Additional effects from announced plant closings or expansions and plant-specific information were also factored into these models.

Figure 5.1.1-5



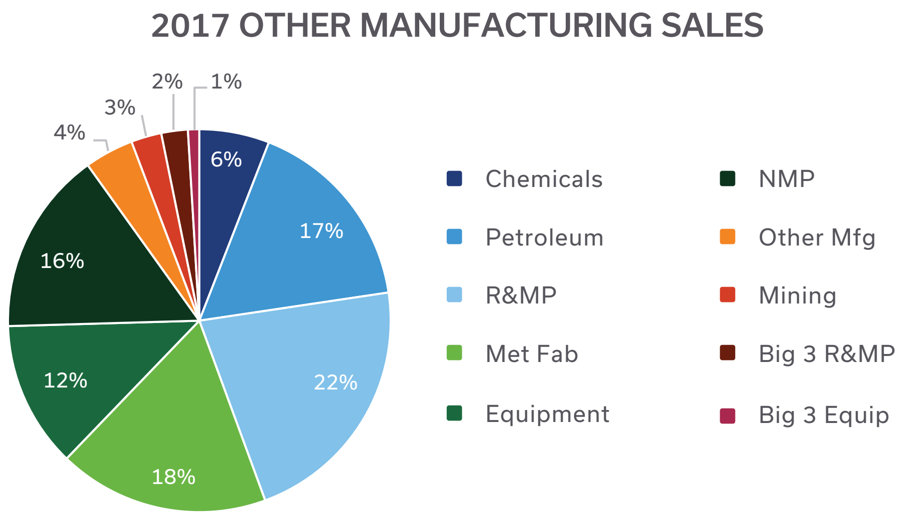
Steel

The steel market is dominated by three large producers that account for almost 60 percent of steel sales. Because of this high concentration and volatility in the market, forecasting steel sales can be difficult. Global market conditions can have a significant effect on local steel production.

Other Manufacturing

The other manufacturing sector of the Industrial class was disaggregated into ten markets and sub-markets: chemicals, petroleum, rubber and plastics (R&MP), mining, non-metal processing (NMP), metal fabrication, manufacturing equipment, other manufacturing, Big Three R&MP, and Big Three manufacturing equipment. Electricity sales for most of these markets were also forecast using regression-based models with automotive production, manufacturing employment and other economic indicators as variables. The relative size of the markets is shown in Figure 5.1.1-6.

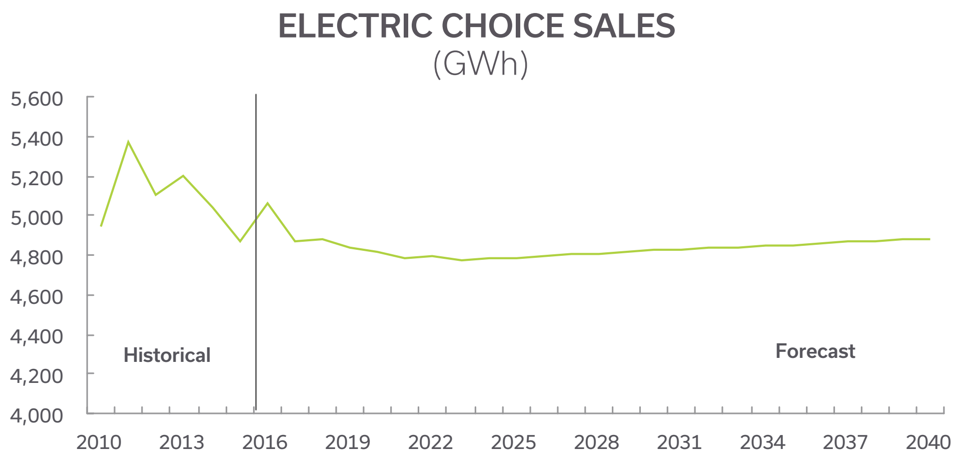
Figure 5.1.1-6



Electric Choice

The Electric Choice sales forecast was based on the temperature-normalized sales expected for 2016. Based on actual sales through February and forecasted sales for March – December, Electric Choice sales were expected to be 4,865 GWh. The forecast for most sub-classes was kept flat at that level. The forecast for the steel sub-class beyond 2017 varied with expected changes in steel production each year. Market clearing prices are not expected to increase significantly from current levels through 2018; therefore, no other changes in Electric Choice sales are forecasted. The Electric Choice sales forecast is shown in Figure 5.1.1-7.

Figure 5.1.1-7



5.1.2 PEAK DEMAND FORECAST METHODOLOGY

The Hourly Electric Load Model (HELM) was used to forecast annual DTEE Service Area and Bundled peak demand. HELM was also utilized to determine monthly peak demands in the forecast period. HELM was developed by the Electric Power Research Institute (EPRI) and aggregates hourly demand profiles from various sales categories or end-uses into a system annual load shape. The annual sales and hourly demand profiles for each sales category or end-use are key inputs to this model.

Normal temperature on the day of the annual peak is assumed to be 83.0°F, which is the mean temperature from Detroit Metropolitan Airport. This value is based upon an average peak-day mean temperature for a 30-year period (1981 through 2010). The mean temperature is calculated as the average of the high and low temperature for the day. The peak day is assumed to occur on a weekday in July or August. In addition, normal temperature conditions were utilized for the projection of weather-sensitive sales.

5.2 Forecast Results

Over the forecast period in the Reference scenario, Service Area sales and peak demand are expected to decline annually an average of 0.1 percent and 0.2 percent, respectively. Bundled sales and peak demand are also expected to decline annually an average of 0.1 percent and 0.2 percent, respectively. The growth rate for Bundled is the same as Service Area due to a steady Electric Choice sales forecast. Figures 5.2-1 and 5.2-2 show the Reference scenario forecast sales and peak demand; sales and peak demand for 2015 are temperature-normalized. The drop from 2016 to 2017 and the increase in 2018 are due to changes in auto production as facilities undergo retooling, which can move volumes significantly.

Figure 5.2-1

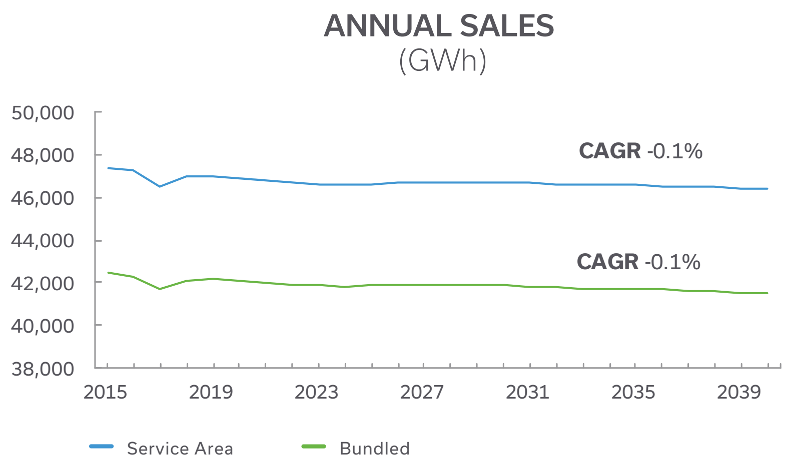


Figure 5.2-2

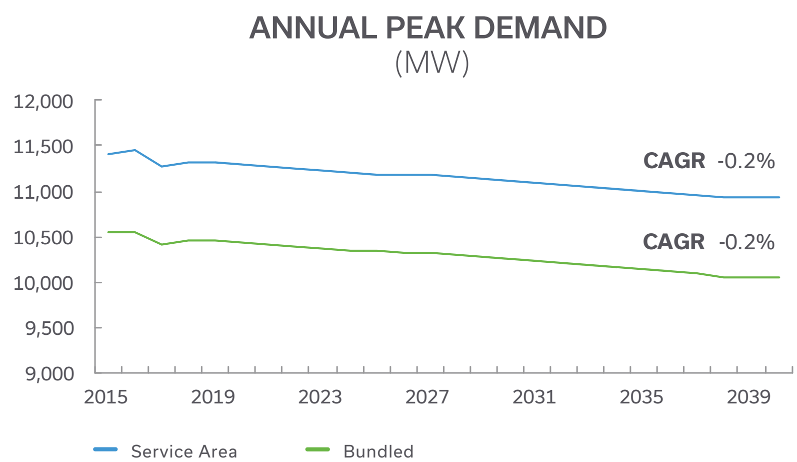


Table 5.2-1 shows DTEE's Service Area sales, net system output, load factor and peak demand for the Reference scenario. Data for 2010-2015 is actual, not temperature-normalized. The forecast for 2016-2040 assumes normal weather.

Table 5.2-1

SERVICE AREA ELECTRIC SALES AND DEMAND

	SALES		LOSSES	OUTPUT		LOAD FACTOR	PEAK	
Year	(GWh)	% Change	(GWh)	(GWh)	% Change	%	(MW)	% Change
2010	50,706		3,541	54,248		53.0	11,687	
2011	51,006	0.6%	3,404	54,410	0.3%	49.5	12,547	7.4%
2012	48,643	-4.6%	3,640	52,282	-3.9%	48.9	12,201	-2.8%
2013	48,379	-0.5%	3,513	51,892	-0.7%	50.8	11,669	-4.4%
2014	47,480	-1.9%	3,579	51,059	-1.6%	53.1	10,970	-6.0%
2015	47,072	-0.9%	3,836	50,908	-0.3%	54.5	10,660	-2.8%
2016	47,180	0.2%	3,441	50,621	-0.6%	50.5	11,453	7.4%
2017	46,525	-4.3%	3,486	50,010	-3.8%	50.6	11,272	-1.3%
2018	46,939	0.9%	3,502	50,441	0.9%	50.9	11,320	0.4%
2019	46,985	0.1%	3,502	50,487	0.1%	50.9	11,314	-0.1%
2020	46,916	-0.1%	3,498	50,414	-0.1%	51.0	11,293	-0.2%
2021	46,793	-0.3%	3,492	50,285	-0.3%	50.9	11,267	-0.2%
2022	46,696	-0.2%	3,487	50,183	-0.2%	51.0	11,240	-0.2%
2023	46,630	-0.1%	3,483	50,113	-0.1%	51.0	11,217	-0.2%
2024	46,610	0.0%	3,481	50,091	0.0%	51.1	11,201	-0.1%
2025	46,633	0.0%	3,482	50,115	0.0%	51.1	11,191	-0.1%
2026	46,724	0.2%	3,487	50,211	0.2%	51.2	11,189	0.0%
2027	46,720	0.0%	3,488	50,207	0.0%	51.3	11,173	-0.1%
2028	46,715	0.0%	3,488	50,203	0.0%	51.4	11,156	-0.2%
2029	46,701	0.0%	3,488	50,189	0.0%	51.5	11,136	-0.2%
2030	46,680	0.0%	3,487	50,167	0.0%	51.5	11,114	-0.2%
2031	46,652	-0.1%	3,485	50,137	-0.1%	51.6	11,090	-0.2%
2032	46,620	-0.1%	3,483	50,103	-0.1%	51.7	11,064	-0.2%
2033	46,578	-0.1%	3,480	50,059	-0.1%	51.8	11,038	-0.2%
2034	46,575	0.0%	3,481	50,056	0.0%	51.8	11,021	-0.2%
2035	46,560	0.0%	3,480	50,040	0.0%	51.9	11,000	-0.2%
2036	46,534	-0.1%	3,479	50,013	-0.1%	52.0	10,977	-0.2%
2037	46,500	-0.1%	3,476	49,976	-0.1%	52.1	10,951	-0.2%

	SALES		LOSSES	OUTPUT		LOAD FACTOR	PEAK	
Year	(GWh)	% Change	(GWh)	(GWh)	% Change	%	(MW)	% Change
2038	46,459	-0.1%	3,474	49,933	-0.1%	52.2	10,924	-0.3%
2039	46,418	-0.1%	3,471	49,889	-0.1%	52.1	10,926	0.0%
2040	46,374	-0.1%	3,468	49,842	-0.1%	52.1	10,928	0.0%
COMPOUND ANNUAL GROWTH RATE 2017-2040								
	-0.01%			-0.01%			-0.13%	

Table 5.2-2 shows DTEE's temperature-normalized Service Area sales by customer class for the Reference scenario. Historical Other class sales include Wholesale for Resale sales as various contracts expired through mid-2014. The growth rate for the Residential class is lower than for the Commercial and Industrial classes, which explains the lower growth rate in peak demand than in sales, as residential sales drive peak demand.

Table 5.2-2

SERVICE AREA TEMPERATURE-NORMALIZED SALES BY CLASS (GWh)

Year	Residential	Commercial	Industrial	Other	Total	% Change
2010	14,980	19,469	11,933	3,210	49,591	
2011	15,213	19,799	11,745	3,136	49,894	0.6%
2012	15,062	19,574	11,909	958	47,503	-4.8%
2013	15,249	19,801	12,388	942	48,379	1.8%
2014	15,115	19,874	12,232	517	47,737	-1.3%
2015	15,055	20,034	11,583	291	46,962	-1.6%
2016	14,953	20,263	11,811	277	47,304	0.7%
2017	14,778	20,147	11,353	246	46,525	-2.2%
2018	14,720	20,219	11,760	240	46,939	0.9%
2019	14,662	20,219	11,870	234	46,985	0.1%
2020	14,625	20,229	11,834	228	46,916	-0.1%
2021	14,578	20,271	11,720	224	46,793	-0.3%
2022	14,540	20,278	11,654	224	46,696	-0.2%
2023	14,500	20,293	11,613	224	46,630	-0.1%

Year	Residential	Commercial	Industrial	Other	Total	% Change
2024	14,459	20,308	11,618	225	46,610	0.0%
2025	14,435	20,340	11,632	225	46,633	0.0%
2026	14,421	20,376	11,701	226	46,724	0.2%
2027	14,406	20,394	11,693	226	46,720	0.0%
2028	14,392	20,412	11,686	226	46,715	0.0%
2029	14,377	20,422	11,676	226	46,701	0.0%
2030	14,363	20,426	11,665	226	46,680	0.0%
2031	14,349	20,423	11,655	226	46,652	-0.1%
2032	14,334	20,414	11,646	226	46,620	-0.1%
2033	14,320	20,395	11,638	226	46,578	-0.1%
2034	14,306	20,415	11,628	226	46,575	0.0%
2035	14,291	20,424	11,620	226	46,560	0.0%
2036	14,277	20,420	11,611	226	46,534	-0.1%
2037	14,263	20,408	11,604	226	46,500	-0.1%
2038	14,249	20,388	11,597	226	46,459	-0.1%
2039	14,234	20,368	11,590	226	46,418	-0.1%
2040	14,220	20,346	11,582	226	46,374	-0.1%
COMPOUND ANNUAL GROWTH RATE 2015-2040						
	-0.23%	0.06%	0.00%	-1.00%	-0.05%	

5.3 Sensitivities

High and low load forecasts were developed for sensitivity analysis within the IRP process. A comparison of growth rates for the Reference scenario, high and low load forecast sensitivities is shown in Table 5.3–1.

Table 5.31

COMPOUND ANNUAL GROWTH RATES (CAGR)

FROM 2015 - 2040	High	Reference Scenario	Low
Service Area Sales	0.4%	-0.1%	-0.7%
Bundled Sales	0.5%	-0.1%	-0.7%
Service Area Peak	0.1%	-0.2%	-0.7%
Bundled Peak	0.1%	-0.2%	-0.7%

Figures 5.3–1 and 5.3–2 show Service Area sales and peak demand for each of the load forecasts.

Figure 5.3-1

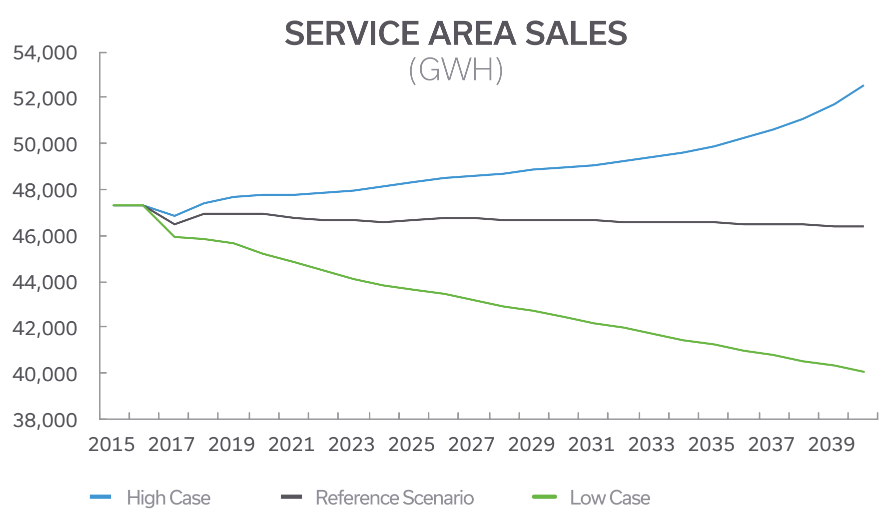
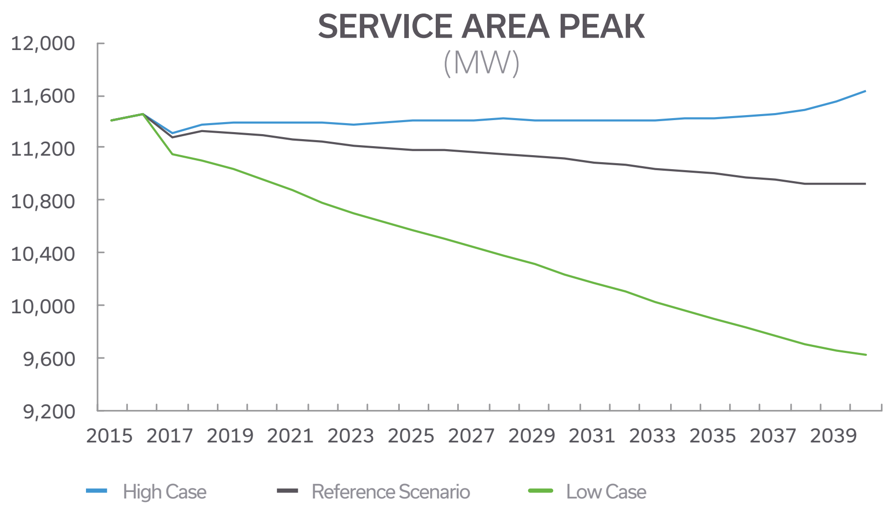


Figure 5.3-2



5.3.1 HIGH LOAD DEMAND

In the high load forecast sensitivity, energy efficient lighting has already reached its peak penetration in the residential market, so no further decline in sales is expected. Consumers ramp up adoption of electric vehicles. Growing population propels higher commercial sales. In addition, southeast Michigan becomes a hub for data centers. Local vehicle production rebounds to 1.9 million vehicles after retooling for new products in 2017 and 2018. Steel production gradually increases as it approaches five million tons a year. Sales, net system output, and peak demand for this case can be found in Appendix B.

5.3.2 LOW LOAD DEMAND

In the low load forecast sensitivity, declining population leads to a loss of residential customers. Solar self-generation further reduces residential sales. Declining population lowers commercial sales. Another university installs a co-generation unit reducing commercial sales. Lower vehicle and steel production reduces industrial sales. Two auto assembly plants are assumed to close. Sales, net system output, and peak demand for this case can be found in Appendix C.

5.4 Forecast Accuracy

DTEE tracks its forecast accuracy on a year-ahead basis. Based on data from 2010 to 2015, the mean absolute percentage error (MAPE) for temperature-normalized Service Area sales is 1.3 percent and for temperature-normalized peak is 0.9 percent. At the customer class level, the MAPE is 1.5 percent for Residential, 1.4 percent for Commercial, and 4.7 percent for Industrial. Tables 5.4-1 and 5.4-2 compare the forecasts to actual temperature-normalized data for 2010 to 2015 for Service Area sales and peak, respectively.

Table 5.4-1

TEMPERATURE-NORMALIZED SERVICE AREA ELECTRIC SALES
(GWh) ABSOLUTE PERCENT VARIANCE

Residential				Commercial		
Year	Actual	Forecast	Variance	Actual	Forecast	Variance
2010	14,980	14,903	0.5%	19,469	19,646	0.9%
2011	15,213	14,621	4.0%	19,799	19,119	3.6%
2012	15,062	14,793	1.8%	19,574	19,907	1.7%
2013	15,249	15,248	0.0%	19,801	19,839	0.2%
2014	15,115	15,359	1.6%	19,874	19,762	0.6%
2015	15,055	15,178	0.8%	20,034	20,394	1.8%
AVERAGE			1.5%			1.4%

Industrial				Total Service Area		
Year	Actual	Forecast	Variance	Actual	Forecast	Variance
2010	11,933	10,903	9.4%	49,591	48,752	1.7%
2011	11,745	12,570	6.6%	49,894	49,517	0.8%
2012	11,909	12,108	1.6%	47,503	47,853	0.7%
2013	12,388	12,600	1.7%	48,379	48,663	0.6%
2014	12,232	12,655	3.3%	47,737	48,535	1.6%
2015	11,583	12,264	5.5%	46,962	48,103	2.4%
AVERAGE			4.7%			1.3%

Table 5.4-2

TEMPERATURE-NORMALIZED SERVICE AREA PEAK
(MW) ABSOLUTE PERCENT VARIANCE

Year	Actual	Forecast	Variance
2010	11,543	11,497	0.4%
2011	11,531	11,477	0.5%
2012	11,426	11,583	1.4%
2013	11,549	11,603	0.5%
2014	11,418	11,624	1.8%
2015	11,403	11,529	1.1%
AVERAGE			**0.9%**

For the last several years, Itron, Inc. has conducted a benchmarking survey of utilities. One of the questions asks for the accuracy of the prior year's sales and peak forecast. As seen in the survey results in Table 5.4-3, DTEE's Service Area sales accuracy is 0.4 percent better than the results of the survey. DTEE's Service Area peak accuracy is 1.5 percent better than the results of the survey. On a customer class basis, DTEE is at or near the survey results.

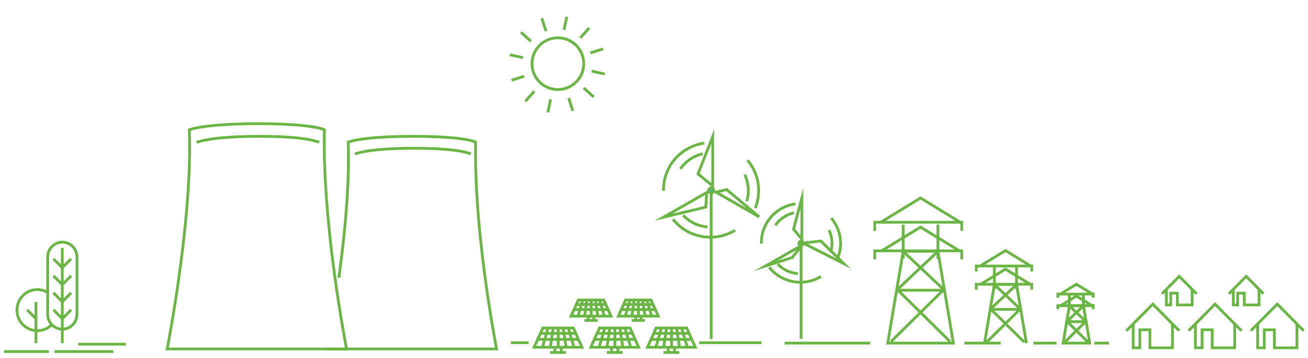
Table 5.4-3

ITRON'S BENCHMARKING SURVEY RESULTS
ABSOLUTE PERCENT VARIANCE

Class	2011	2012	2013	2014	2015	Average	DTEE Average 2011-2015
Residential	1.7%	1.5%	1.7%	1.5%	1.9%	1.6%	1.7%
Commercial	1.7%	2.0%	2.1%	1.3%	1.6%	1.7%	1.6%
Industrial	3.2%	3.2%	4.4%	3.4%	3.0%	3.5%	3.8%
Total	NA	1.6%	1.5%	1.3%	1.9%	1.6%	1.2%
Peak	1.9%	2.7%	3.1%	2.4%	2.7%	2.5%	1.0%

SECTION 6

EXISTING RESOURCES AND OPERATIONS



6. Existing Resources and Operations

A plan for the future requires a thorough analysis of existing energy resources. DTEE has a large fleet of generation consisting of base load coal and nuclear power plants, natural gas and oil-fired peaking units, pumped storage, and wind and solar parks. In addition, DTEE has entered into several power purchase agreements, most sourced with renewable generation. DTEE plans to retire three coal-fired power plants in the early 2020s. Energy efficiency programs targeting all customer groups are expected to deliver annual energy savings of 1.5 percent through 2021.

6.1 Existing Resources Overview

DTEE's 7,044 MW of fossil steam generation contains coal-fired units that provided 6,259 MW of capacity shown in Table 6.1-1, and a natural gas-fired steam unit that provided an additional 785 MW (Greenwood Power Plant).

Table 6.1-1: Coal Plant Description

Coal Steam Plants	Net Summer Capability	No. Units
Belle River (DTEE ownership)	1,034 MW	2
Monroe	3,066 MW	4
River Rouge	272 MW	1
St. Clair	1,367 MW	6
Trenton Channel	520 MW	1
Total Coal Capacity (steam)	6,259 MW	14

The Michigan Public Power Agency (MPPA) is a joint owner of Belle River Power Plant, with ownership entitlement of effectively 18.61 percent (234 MW) of the plant. The MPPA ownership of Belle River is not included in the 1,034 MW Belle River Power Plant's capability, shown in Table 6.1-1.

DTE Electric's peaking plants, along with DTEE's ownership share of the Ludington Pumped Storage facility (jointly owned with Consumers Energy(CE)) are shown in Table 6.1-2. Consumers Energy's ownership entitlement is effectively 51 percent of the plant.

Table 6.1-2: Pumped storage and Peaking unit description

Pumped Storage and Peaking	Net Summer Capability	No. Units
Gas/Oil Turbine Peaking (10 locations)	1850 MW	39
Diesel Peaking (10 locations)	112 MW	46
Total Peaking Capacity	1,962 MW	84
Ludington Pumped Storage	992 MW	6
Total Pumped Storage/Peaking Capacity	**2,954 MW**	**90**

6.2 Coal Plants

Belle River Power Plant (BR) sits in both East China Township and China Township along the St. Clair River. The plant is co-owned by DTEE and the MPPA. MPPA owns 37.22 percent of Unit 1 and is entitled to 18.61 percent of the total plant electrical capacity and energy output. MPPA is a consortium of 18 municipalities that aggregate together to provide for the electrical needs of their customers. Belle River is a two-unit plant, and each unit has a net dependable capacity rating of 635 MW. Unit 1 was placed into service in 1984; Unit 2 began commercial operations in 1985. The 2012-2016 average capacity factor for Unit 1 was 64.6 percent and for Unit 2 was 67.1 percent. Both units are coal-fired and utilize low-sulfur western (LSW) coal as their primary fuel source. Fuel oil is also utilized for unit startups and can be utilized as a supplemental fuel source during peak load conditions. The units are equipped with multiple emission control technologies, including low NO_x burners, over-fire air (OFA) systems, cold-side electrostatic precipitators (ESPs), dry sorbent injection (DSI), and activated carbon injection (ACI). The plant also utilizes reduced emissions fuels (REF).

Monroe Power Plant (MN) is in Monroe, Michigan along Lake Erie. It is a four-unit coal-fired steam plant. Unit net dependable capacity ratings are 758 MW, 773 MW, 773 MW, and 762 MW respectively for Units 1-4. The units were sequentially placed into service between 1971 and 1974. The 2012-2016 average capacity factor for Unit 1 was 55.8 percent, Unit 2 was 51.0 percent, Unit 3 was 61.9 percent and Unit 4 was 59.1 percent. The units utilize coal as their primary fuel source, while also utilizing fuel oil for unit startups and as a supplemental fuel source during peak load conditions. Monroe blends various coal types based on electrical and fuel market pricing dynamics. Coal types utilized at Monroe include LSW, mid-sulfur eastern (MSE), high-sulfur eastern (HSE), along with petroleum coke. The units are equipped with multiple emission control technologies, including low NO_x burners, OFA systems, ESPs, flue gas desulphurization (FGD) scrubbers and selective catalytic reduction (SCR). The plant also utilizes REF.

River Rouge Power Plant (RR) is in River Rouge, Michigan along the Detroit River. Unit 1 and Unit 2 have been previously retired and River Rouge is now a single-unit coal-fired steam plant with a net dependable capacity rating of 272 MW. Unit 3 began commercial service in 1958. The 2012-2016 average capacity factor of the unit was 49.1 percent. River Rouge Unit 3 utilizes coal as its primary fuel source while also utilizing low cost blast furnace gas (BFG) and coke oven gas (COG) as additional fuel sources to the extent of their availability. Natural gas is also utilized as a fuel source for unit startups and as a supplemental fuel source during peak load conditions. River Rouge utilizes blends of LSW and low-sulfur southern (LSS) coals, based on electrical and fuel market pricing dynamics. The unit is equipped with multiple emission control technologies, including low NO_x burners, OFA, ESPs, DSI, and ACI systems.

St. Clair Power Plant (SC) is in St. Clair, Michigan along the St. Clair River. It is a six-unit coal-fired steam plant. The net dependable capacity ratings of the units are 151 MW, 154 MW, 160 MW, 151 MW, 311 MW and 440 MW for Units 1-4, 6 and 7 respectively. The 2012-2016 average capacity factor for Unit 1 was 45.0 percent, Unit 2 was 40.8 percent, Unit 3 was 38.7 percent, Unit 4 was 45.8 percent, Unit 6 was 39.1 percent and Unit 7 was 43.5 percent. St. Clair Units 1-4 began service in 1953-1954, Unit 6 began service in 1961, and Unit 7 began service in 1969. St. Clair utilizes coal as its primary fuel source. Fuel oil or natural gas is also utilized as a fuel source for unit startups and as a supplemental fuel source during peak load conditions on specific units. St. Clair utilizes blends of LSW and HSE coals based on electrical and fuel market pricing dynamics. The units are equipped with multiple emission control technologies including low NO_x burners, OFA, ESPs, DSI, and ACI systems. The plant also utilizes REF.

Trenton Channel Power Plant (TC) is in Trenton, Michigan along the Detroit River. Units 7A and 8 were retired in 2015 and 2016. Trenton Channel Unit 9, which remains in service, was commissioned in 1968. The unit's net dependable capacity rating is 520 MWs, and its 2012-2016 average capacity factor was 51.4 percent. Trenton Channel Unit 9 utilizes coal as its primary fuel source. Fuel oil is also utilized as a fuel source for unit startups and as a supplemental fuel source during peak load conditions. Trenton Channel utilizes blends of LSW and HSE coals, based on electrical and fuel market pricing dynamics. The unit is equipped with multiple emission control technologies including low NO_x burners, OFA, ESPs, DSI, and ACI systems.

6.3 Planned Retirements

In making decisions regarding retirement of a unit or group of units, DTEE used the integrated resource planning process, weighting the Planning Principles of reliability, affordability, clean, flexible and balanced, compliant, and reasonable risk. The Company evaluated the economics associated with continued operation of the units, including the market value, the capital expenditures that would be needed to make the units compliant with emergent environmental regulations, and the ongoing O&M and capital expenditures to operate and maintain the aging units. While future environmental regulation is not always certain, the Company analyzed known and likely regulations and the costs to comply with them. In addition to the economic modeling, or NPV analysis, the Company considered the other factors that are part of the Planning Principles, and made its decisions.

In the second quarter of 2016, the Company evaluated the economics associated with continued operation of its coal-fired units, considering the capital expenditures as shown in Table 6.3-1 that would be required to bring the units into compliance with two environmental regulations. Due to changes to the Steam Electric Effluent Limitation Guidelines (ELG) and the Cooling Water Intake Regulations (316(b)), DTEE performed an analysis to evaluate the effect of investing capital to comply with revised regulations or retiring units prior to the compliance deadline dates. The assumptions for this analysis were determined by the subject matter experts (SMEs) in the Company's Environmental Compliance, Fossil Generation, and Business Planning and Development departments.

Table 6.3-1: Capital Required to Meet Environmental Requirements

SUMMARY OF REQUIRED CAPITAL								
Unit		SC 1-4	SC 6	SC 7	TC9	RR3	BR	MN
Capital (M$)	ELG	$60	$20	$20	$20	$20	$30	$200
	316(b)	$25	$10	$15	$25	$4	$1	$50

As appropriate, the Company established groups of units with similar operating characteristics and economics to evaluate together. Units that did not fit into a group were considered individually. St. Clair units 1-4 were considered as a group, Belle River 1 and 2 as a group, and Monroe 1-4 as a group; St. Clair 6, St. Clair 7, Trenton Channel 9, and River Rouge 3 were all considered individually.

The economic evaluation portion of the retirement analysis compared a case in which the retirement of each of the unit groups and the other four individual units before 2023, when retrofits would be required, versus a case that assumed the Company would spend the capital to make the retrofits and extend unit retirements to a later date. In all cases, the units were assumed to be replaced with combined cycle.

The results of the study are in Table 6.3-2.

Table 6.3-2

NPV (MILLION $) RETIREMENT CASE MINUS RETROFIT AND KEEP UNIT IN OPERATION							
Unit	SC 1-4	SC 6	SC 7	TC9	RR	BR	MN
Base Retrofit Case	($84)	($50)	($32)	($31)	($36)	$232	$2,085

Negative numbers indicate it is better to retire before 2023; positive numbers indicate more value to keep the units until 2028 or later. The economics from this study indicate that it is advantageous to retire St. Clair, Trenton 9, and River Rouge before the environmental retrofits are required in 2023, and to keep Belle River and Monroe and make them compliant to the ELG and 316(b) regulations. These results are in alignment with the Tier 1 and Tier 2 groupings presented in Section 6.1.

DTEE ran higher capital sensitivities, low capacity market price sensitivities, and a CO_2 sensitivity for each of the unit groups except Monroe. The results are shown in Table 6.3-3.

Table 6.3-3: Results of the Economic Retirement Analysis NVP (Million $)

Unit	SC 1-4	SC 6	SC 7	TC9	RR	BR
Base Retrofit Case	($84)	($50)	($32)	($31)	($36)	$232
High ELG Capital	($108)	($58)	($40)	($39)	($44)	$219
CO_2 Prices	($127)	($68)	($52)	($62)	($63)	$128
Low Capacity Price	($82)	($1)	$10	$5	$11	$215

The results of the sensitivities agreed with the base retrofit case: it is advantageous to forgo the capital expenditure to achieve environmental compliance on units St. Clair 1-4, 6, and 7, Trenton Channel 9, and River Rouge, and retire the units with a combined cycle replacement. For Belle River, the results show it is more economical to spend the money on the retrofit and keep the unit at least another five years. In the low capacity price case, the NPV is positive toward continued operation for units St. Clair 7, Trenton 9, and River Rouge; however, the values are still close to even and outweighed by the other sensitivities.

Due to the modeling methodology of replacing a 500 MW block of coal unit plus market purchases with a larger combined cycle (1500 MW versus 1000 MW), the low capacity price sensitivity results are more favorable than the base retrofit case for the St. Clair, Trenton Channel, and River Rouge units. SC6, SC7, TC9, and RR3 are each smaller than 500 MW. Therefore, in these cases, when the coal unit plus capacity purchases become lower in price, the results are less expensive than the case with the higher capacity purchase price and favor keeping the unit in operation.

Based on the retirement study, the retirement schedule for coal units was generated; see Table 6.3-4.

Table 6.3-4: Coal Unit Retirement Dates

Unit	Announced date	Assumed date for IRP modeling
River Rouge 3	Before Dec 2023	May 31, 2020
St. Clair 1-4	Before Dec 2023	May 31, 2022
St. Clair 6	Before Dec 2023	May 31, 2022
St. Clair 7	Before Dec 2023	May 31, 2023
Trenton Channel 9	Before Dec 2023	May 31, 2023
Belle River 1	2030	May 31, 2029
Belle River 2	2030	May 31, 2030
Monroe 1-4	2040	Post IRP study period (2040)

The date of May 31 is used in the IRP modeling, because that date is in alignment with the MISO capacity year.

6.4 Peaking Units

DTEE has approximately 1,962 MW of peaker generating capability in its fleet, based on the summer capacity ratings of these units. As shown in Table 6.4-1, DTEE has 84 diesel and gas turbine peakers located at 20 different sites. The 2012-2016 average capacity factor for the peaking units was 3.4 percent.

Table 6.4-1: DTE Electric Peaking Units

Peakers	Net Summer Capability	No. Units
Gas/Oil Turbine Peaking (10 locations)	1,850 MW	38
Diesel Peaking (10 locations)	112 MW	46
Total Peaking Capacity	1,962 MW	84

Gas turbines have significantly higher winter capacity ratings when compared to their summer ratings because ambient air temperature affects the quantities of fuel that can be combusted and thereby the output capacity of the units. Utilization of summer ratings provides a better representation of the generating capacity available to meet peak loads in the traditionally summer peaking DTEE system, and this number is utilized when determining the MISO capacity planning reserve requirements.

Greenwood Power Plant is in Avoca Township, Michigan. It is a single unit natural gas-fired steam plant and has a net maximum capacity rating of 785 MW. The unit was commissioned in 1979, and its 2012-2016 average capacity factor was 4.3 percent. The unit utilizes natural gas as its primary fuel source for electrical generation. Fuel oil is also utilized as the fuel source for unit startups. The unit is equipped with low NO_X burners and OFA systems for emissions control.

6.5 Nuclear Unit

Enrico Fermi 2 Power Plant

The Fermi 2 Power Plant is in Frenchtown Twp., Michigan. It is a base loaded single-unit boiling water reactor with an approximate generating capacity of 1,161 MWnet. It was commissioned in 1988. Fermi 2 received a 20-year license renewal in 2016, allowing that unit to continue to operate until 2045.

6.6 Pumped Storage Unit

The Ludington Pumped Storage facility is in Ludington, Michigan alongside Lake Michigan. It is a six-unit hydroelectric power plant with each unit originally rated at 312 MW_{net}. The plant is co-owned by DTEE and Consumers Energy; DTEE owns 49 percent and CE owns 51 percent. CE, as the majority owner, is also the operating authority. The units were commissioned in 1973 and their 2012-2016 average capacity factors were 16 percent, 12 percent, 16 percent, 12 percent, 8 percent, and 12 percent respectively. Starting in 2015 the units have been going through a maintenance overhaul upgrade one unit at a time. These upgrades will provide 34 MW of increased generation (DTEE ownership) for each unit, a total of 204 MW for the plant. The upgrades to all six units will be completed by 2020, at which time DTEE-owned capacity in Ludington is forecasted to be 1,122 MW.

6.7 Renewables

6.7.1 WIND

In 2008, Michigan's legislature passed PA 295, creating a renewable portfolio standard requiring 10 percent renewable energy by 2015. Since that time, DTEE has met the requirements of the law, and currently over 90 percent of DTEE's renewable fleet consists of wind energy, the most economical renewable investment in Michigan right now.

DTEE owns seven wind parks with a combined capacity of 451 MW within Michigan. All the parks are located in the lower peninsula of the state, with six of them sited in the Thumb region and one in central Michigan. The nameplate capacities of the parks range from 14 MW to 112 MW, and the fleet consists of 277 wind turbine generators. An additional park, Pine River, is scheduled to be completed in 2018 with an installed capacity of 161 MW and 65 installed wind turbines located in central Michigan. Table 6.7.1-1 provides detailed information about DTEE-owned wind parks.

Table 6.7.1-1 DTE Electric-Owned Wind Parks

Park Name	Capacity MW	Wind Turbines	Location	COD Year
Gratiot Wind Park	102.4	64	Central, MI	2011
Minden	32.0	20	Thumb, MI	2013
McKinley	14.4	9	Thumb, MI	2013
Sigel	64.0	40	Thumb, MI	2013
ECHO	112.0	70	Thumb, MI	2014
Brookfield	74.8	44	Thumb, MI	2014
Pinnebog	51.0	30	Thumb, MI	2016
Pine River	161.3	65	Central, MI	2018 (est.)

DTEE also has entered into six wind PPAs with a combined capacity of 458 MW. Along with the energy and capacity attributes, DTEE also receives the Renewable Energy Credits (RECs) produced by these parks for use in complying with Michigan's renewable portfolio standard. Table 6.8-2 in Section 6.8 Power Purchase Agreements outlines all DTEE PPAs.

6.7.2 SOLAR

DTEE has completed its company-owned SolarCurrents pilot program which consists of approximately 14.4 MW_{AC} across 28 sites throughout the electric service territory. Through the pilot, DTEE built strong and sustaining relationships with solar manufacturers, distributors, and contractors. DTEE experimented with various technologies and approaches to building solar, and worked with its partners at the host sites of the arrays to help educate the community about solar energy. The site sizes range from less than 100 kW_{AC} to almost 2 MW_{AC}. The architectures of the sites vary from site to site and include ground-mount, roof-mount, and carport. DTEE's newest and largest 50 MW_{AC} solar project came online in 2017 and was commissioned in 2017. This project consists of 48 MW_{AC} located in Lapeer, MI and 2 MW_{AC} located at O'Shea Park in Detroit, MI. DTEE's Owned Solar parks are shown in Table 6.7.2-1.

Table 6.7.2-1: DTE Electric-Owned Solar Parks

Park Name	Capacity (MW_{AC})	Location (County)	Starting Year
SCIO Solar Array	0.056	Washtenaw	2010
Blue Cross Blue Shield	0.200	Wayne	2011
Monroe County Community	0.500	Monroe	2011
Ford Solar Array	0.500	Wayne	2011
Training and Development Center	0.380	Wayne	2011
General Motors Solar Array	0.500	Wayne	2011
DTE Headquarters (DECo Project #3)	0.081	Wayne	2012
Mercy High School	0.375	Oakland	2012

Park Name	Capacity (MW_{AC})	Location (County)	Starting Year
Warren Consolidated Schools	0.189	Macomb	2012
General Motors Orion Assembly	0.300	Oakland	2012
Huron Clinton Indian Springs Metro	0.495	Oakland	2012
Wil-Le Farms	0.484	Huron	2012
Immaculate House of Mary	0.500	Monroe	2012
University of Michigan - North Campus Center	0.430	Washtenaw	2012
University of Michigan - Institute of Science	0.241	Washtenaw	2013
Riopelle Farms	0.500	Huron	2013
St. Clair RESA	0.503	St. Clair	2013
Leipprandt Orchards	0.503	Huron	2013
Hartland Schools	0.444	Livingston	2013
McPhail	0.816	Oakland	2014
Domino Farms	1.000	Washtenaw	2015
Thumb Electric Cooperative	0.605	Tuscola, Bay, & Saginaw	2015
Ford World Headquarters	0.780	Wayne	2015
Ashley / Romulus	0.684	Wayne	2015
Brownstown	0.500	Wayne	2016
Greenwood Energy Center	1.417	St. Clair	2016
Ypsilanti	0.703	Washtenaw	2016
General Motors Transmission Plant	0.748	Macomb	2016
Demille Rd	28.00	Lapeer	2017
Turrill Rd	20.00	Lapeer	2017
O’Shea	2.000	Wayne	2017

6.8 Power Purchase Agreements

DTEE has entered into various PPAs that have been approved by the MPSC under PA 2/PURPA and PA 295.

The Public Utility Regulatory Policies Act of 1978 (PURPA) requires electric utilities to purchase power from qualifying facilities (QFs) at the utilities' avoided cost, provide back-up power to QFs, interconnect with QFs, and operate with QFs under reasonable terms and conditions.

PA 2 of 1989 was enacted by Michigan to require utilities with greater than 500,000 customers to enter into PPAs for both energy and capacity from certain landfill gas and solid waste QFs.

PA 295 of 2008 was enacted by Michigan to require certain renewable energy standards to be met by utilities, with 50 percent required to be owned by third parties.

The Company currently has 11 PA 2/PURPA contracts and nine PA 295 contracts for both energy and capacity. The Company also receives capacity credit for customer-owned generation in the amount of 5.4 MW. The Company has capacity rights from both PURPA/PA 2 and 2008 PA 295 Renewable Energy Contracts, which are distinct from DTEE-owned Renewable Energy Systems. The Company expects a total unforced capacity (UCAP) value of 202 MW in the 2017 planning year capacity credit associated PPAs (including customer-owned generation). The contracts are listed in Tables 6.8-1 and 6.8-2 with their corresponding expiration dates and UCAP values.

Table 6.8-1: PA 2 and PURPA Contracts

P.A. 2/PURPA Facility	Expiration Date	Generation Type	UCAP (MW)
Ann Arbor - Barton Dam	4/1/2036	Hydro	0.8
Ann Arbor – Superior	5/1/2036	Hydro	0.6
STS French Landing	1/30/2039	Hydro	1.6
Charter Township Ypsilanti	1/1/2028	Hydro	2.0
Greater Detroit Resource Recovery Facility	6/30/2024	Waste	60.1
Riverview Energy Systems	8/13/2027	Landfill Gas	5.5
Sumpter Energy Associates (Station #1)	7/13/2033	Landfill Gas	17.8
Wayne Energy Recovery	8/13/2027	Landfill Gas	0.7
Lyon Electric Generating	9/21/2030	Landfill Gas	Combined with Arbor Hills
Turbine Power Limited Partnership - Arbor Hills	6/12/2031	Landfill Gas	14.4
Ann Arbor Landfill	4/29/2033	Landfill Gas	0.6

Table 6.8-2: P.A. 295 Agreements

P.A. 295 Agreement	Expiration Date	Generation Type	UCAP (MW)
Heritage Stoney Corners Wind Farm I, LLC	1/1/2030	Wind	4.2
L'Anse Warden Electric Company, LLC	1/1/2032	Biomass	14.7
WM Renewable Energy, LLC	1/1/2032	Landfill Gas	2.8
Gratiot County Wind, LLC	1/1/2033	Wind	19.2
Blue Water Renewables, Inc.	1/1/2032	Biomass	2.8
Tuscola Bay Wind, LLC	1/1/2033	Wind	16.8
Tuscola Wind II, LLC	1/1/2034	Wind	17.3
Pheasant Run Wind, LLC	1/1/2034	Wind	12.1
Big Turtle Wind Farm, LLC	1/1/2035	Wind	2.7

6.9 Fuel Management for Existing Resources

6.9.1 FUEL FORECASTING

DTEE's fuel forecast process establishes the basis for its fuel procurement process. Forecasted delivered costs for various fuel types are utilized to determine DTEE's generation units' most economical fuel blending and dispatch strategies in the MISO market. The forecasted delivered costs are determined by using existing contract prices and transportation rates, forecasted forward market prices, and forecasted transportation rates.

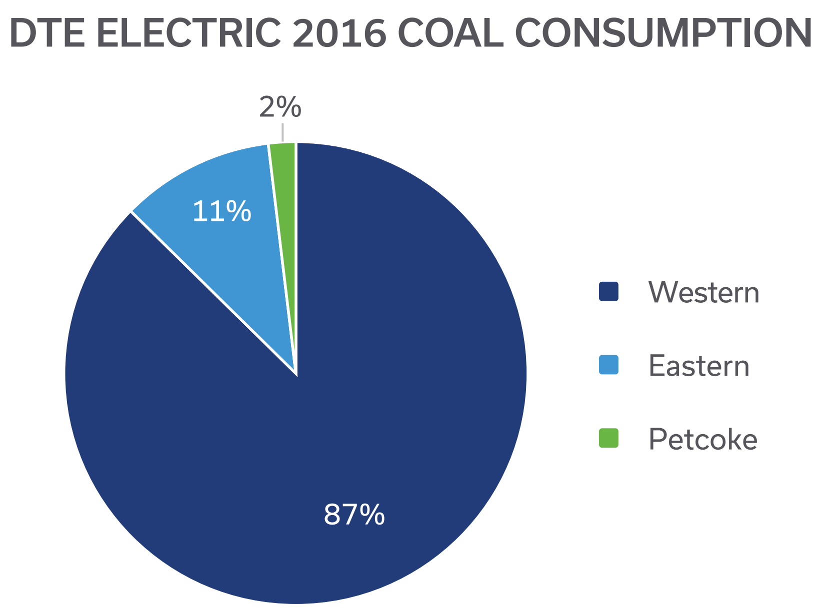
Near-term (up to two years) forecasted market coal prices are based upon market information obtained from an over-the-counter coal broker, while longer term (three to five years) coal costs are derived by applying an inflation index factor to the near-term projection. The forecasted coal transportation rates are computed by applying adjustments to current contract prices using forecasted rail cost adjustment factors based on historical data, along with fuel surcharges based on diesel oil forward pricing.

Petroleum coke (petcoke) forecasted prices are determined by applying an inflation index factor to the current contract price.

The forecasted delivered cost of fuel oil is determined by using the New York Mercantile Exchange (NYMEX) futures prices.

The forecasted delivered cost of natural gas is determined by using the Chicago Mercantile Exchange (CME) Group/NYMEX futures prices for the MichCon CityGate and Dawn hubs, in addition to expected natural gas transportation costs.

Figure 6.9.1-1



DTEE's coal-fueled power plants consume a combination of LSW, HSE, and LSS coal types, as shown in Figure 6.9.1-1. Western coal (LSW) accounts for approximately 87 percent of the Company's coal consumption annually due to its favorable pricing and emissions when compared to the eastern (HSE and LSS) coal types. Although LSW is historically cheaper on a per ton delivered basis, most of the Company power plants have the ability to blend the previously mentioned eastern coal types with LSW in an effort to utilize the higher heat content of the eastern coal types and maximize production during high market opportunities. The Company burns 100 percent LSW on all its coal burning units when the market and fuel prices dictate (typically in lower cost market/demand periods) or can shift to higher eastern (lower western) blends in higher market/demand periods. Blending of western and eastern coal types maximizes customer value while maintaining environmental and regulatory compliance.

6.9.2 FUEL INVENTORY MANAGEMENT

The Company has an ongoing strategy to maintain its coal inventory in order to provide a reliable supply of fuel while optimizing the cost and constraints of managing. An inventory target, maximum, and lower escalation level is established for all coal types at each site. These inventory levels are based on the site's forecasted consumption and take into account any foreseeable transportation or weather related constraints that may impede future deliveries. The Company modifies these inventory levels throughout the year as applicable.

6.9.3 FUEL PROCUREMENT

DTEE manages price risk and secures its necessary coal requirement by layering in its coal purchases in such a way that each year it has a portfolio of long-term and short-term contracts. The long-term contracts secure a large percentage of the forecasted requirement to ensure the Company has a secure supply of coal to provide reliable generation. The short-term contracts and spot purchases allow the Company to accommodate variations in the overall requirement due to operational or blend changes, as well as to provide opportunities to take advantage of favorable market conditions. As the forecasted years become closer to the current year, a greater portion of the requirement is fulfilled with long-term contracts, while leaving a smaller portion open for short-term contracts and spot purchases as shown in Figure 6.9.3-1.

Figure 6.9.3-1

For coal transportation, the Company has been able to leverage market conditions and multiple delivery routes and carriers to negotiate some of the most competitive delivered fuel prices to all its power plants. Additionally, DTEE continues to aggressively market coal and transshipment services to third parties through its subsidiary, Midwest Energy Resources Company (MERC). Third-party revenues and the equity received from MERC's joint venture contribute to a reduction in DTEE's fuel expense and, ultimately, the rates for DTEE's electric customers. The Company also maintains a railcar fleet, not only to facilitate control of delivery of coal but also to optimize the cost savings associated with rail transportation.

The Company's Monroe Power Plant is equipped with FGD and SCR equipment for the control of air emissions. This equipment makes it capable of burning petcoke as a fuel. Petcoke is an economic fuel that provides higher heat content than the other coal types purchased by the Company. DTEE secures its petcoke supply under term agreements and purchases spot volumes when consumption is greater than the contracted supply. Petcoke is delivered primarily via truck, but can also be delivered via lake vessel or rail.

The Company uses diesel fuel oil for startup and over-fire capabilities at coal-fired generating units. No. 2 diesel fuel oil and No. 1 diesel fuel oil (colder temperatures) are used at the Company's diesel peaking generator units. Agreements are in place for fuel oil supply and transportation. Fuel oil is ordered as needed and delivered via truck to the respective site. Fuel oil supply and transportation pricing is market index based with a constant markup applied by the supplier.

DTEE uses natural gas as the primary fuel at its Greenwood, Renaissance, and Dean generating sites and other smaller peaking units, in addition to providing over-fire capabilities at some of its coal-fired generating units. Depending on the location, natural gas and natural gas transportation is procured directly from supply and transportation providers, via third-party marketers, or from local distribution companies.

The Company's Fermi 2 plant is the only nuclear fueled site within its current generation portfolio. Fermi 2's fuel expense is based on assumptions related to how the unit will operate in future years, including capacity factor, fuel bundle loading quantities, fuel component prices, and refueling outages, which occur approximately every 18 months. The plant was refueled in April of 2017 and subsequently entered into Operating Cycle 19. The plant's next refueling outage is scheduled to occur during the third quarter of 2018, after which it will enter into Operating Cycle 20. DTEE has variable commitments, which cover 100 percent of the Company's uranium ore, conversion, and enrichment requirements through 2025 operations. Fabrication contracts apply through at least Operating Cycle 21.

6.10 Demand Response

DTEE's demand response programs have been part of its resource portfolio since the late 1960s. Starting with direct load control of electric water heaters and expanding into air conditioners and other tariffs, DTEE has developed a portfolio of demand response products and services. These demand response programs are designed to help reduce enrolled customers' energy use during peak hours, providing value to both the utility and the customer through lower capacity costs. DTEE has developed a top decile demand response portfolio and is recognized as a pioneer in the development of direct load control demand response programs.

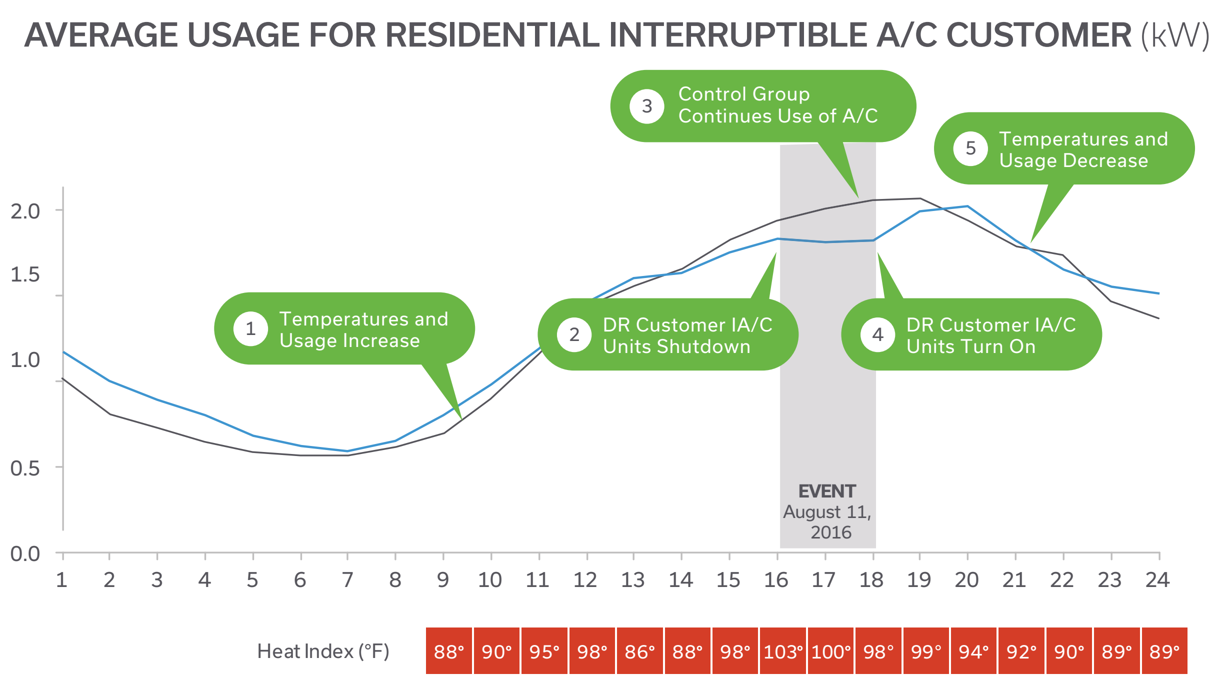
DTEE is currently engaged in evaluating new demand response programs, customer effectiveness, and program acceptance as it continues to develop demand response resources.

6.10.1 GENERAL BENEFITS OF DEMAND RESPONSE

Many benefits can accrue to DTEE customers due to demand response programs, including avoided cost savings, reduced capacity purchases, delayed generating asset need, risk reduction, and energy security.

Avoided electric energy and capacity costs are based upon the costs an electric utility would incur to either construct or operate new electric power plants or other IRP alternatives, or to operate existing power plants. The energy component includes the costs associated with the production of electricity, while the capacity component includes costs associated with the capability to deliver electric energy during peak load periods. An example is shown in Figure 6.10.1-1.

Figure 6.10.1-1



6.10.2 EXISTING DEMAND RESPONSE PROGRAM OFFERINGS

Current demand response programs include offerings available to Residential customers, Commercial and Industrial customers (C&I), and pilot programs focused on reducing on-peak energy consumption. While the programs can differ in delivery and design, the on-peak period for DTEE is between June and September and the peak hours are traditionally between 3 p.m. and 7 p.m. Monday through Friday, not including any federal holidays.

Each program offers customers different options of products, customer incentives, tariff structures, and education based on their risk profiles and willingness to curtail during peak hour events. The program categories are:

- Residential Programs offer homeowners products and tariffs to reduce on-peak electrical usage. The programs focus on heating, ventilating and air conditioning (HVAC); energy education; and behavioral programs.
- C&I Programs offer businesses tariff-based products, which render a lower overall cost for providing capacity relief when called upon. The customers can optimize their on-peak energy usage to reduce the effect of lighting, boilers, pumps, compressors, and others to provide capacity when called upon.
- Pilot Programs focus on new and emerging experimental programs to fit longer-term program portfolio needs, test the cost-effectiveness of emerging technologies, and assess customer adoption of new technologies and market acceptance of existing technologies using new approaches.

6.10.3 RESIDENTIAL PROGRAMS

DTEE offers a variety of residential programs.

Residential Interruptible Space-Conditioning Rate (D1.1): This program consists of a separately metered service connected to the customer's central A/C or heat pump. DTEE will turn off the A/C condenser by remote control on selected days for intervals of no longer than thirty minutes in any hour, for no more than eight hours in any one day. Interruptions may include interruptions for, but not limited to, maintaining system integrity, making an emergency purchase, economic reasons, or when available system generation is insufficient to meet anticipated system load. Customers are provided an approximate 15 percent rate discount on the A/C load for participation on this tariff.

Residential Time of Day Service Rate (D1.2): DTEE customers can pay a lower energy charge for kWh during off-peak hours (7 p.m. to 11 a.m.) than on-peak hours (11 a.m. to 7 p.m.) Monday through Friday. While not a callable program, the Time of Use rate leads to customers shifting energy usage patterns, lowering overall system demand.

Dynamic Peak Pricing Rate (D1.8): Residential customers can elect to have a tiered Time of Use rate with a critical peak event. The rate is designed to allow customers to manage their electric costs by reducing or shifting load during high cost periods. The rate has 20 four-hour events that can be called by 6 p.m. the day before to allow customers to further shift their energy usage and save.

Water Heating Service Rate (D5): The residential option for electric water heater controls is similar to the Interruptible Space-Conditioning rate in that the water heater has to be separately metered with a load control device that is activated by the utility.

6.10.4 COMMERCIAL AND INDUSTRIAL PROGRAMS

The C&I demand response programs consist of many individual tariffs and program options.

Dynamic Peak Pricing Rate (D1.8): Commercial customers can elect to have a tiered Time of Use rate with a critical peak event. The rate is designed to allow customers to manage their electric costs by reducing or shifting load during high cost periods. The rate has 20 four-hour events that can be called by 6 p.m. the day before to allow customers to further shift their energy usage and save.

Interruptible General Service Rate (D3.3): This offering is designed to help secondary voltage C&I customers save on their energy charges. Customers can elect to have a separately metered and wired service with all the load associated with the meter subject to interruption. Customers can install utility signaled control equipment or use an interval/AMI meter to establish their compliance with the interruption signal, when given.

Water Heating Service Rate (D5): For the commercial secondary voltage option for electric water heater controls, similar to the Interruptible Space-Conditioning rate, the water heater has to be separately metered with a load control device that is activated by the utility.

Interruptible Supply Rate (D8): Available to primary voltage customers who contract for an established interruptible capacity at their location of not less than 50 kW. Customer participation on this rate is limited to 300 MW in total.

Alternative Electric Metal Melting (Rider 1.1): Commercial customers who operate electric furnaces for the reduction of metallic ores or metal melting can subscribe to this interruptible rate product.

Electric Process Heat (Rider 1.2): Commercial customers who use electric heat as an integral part of the manufacturing process can subscribe to this interruptible rate product.

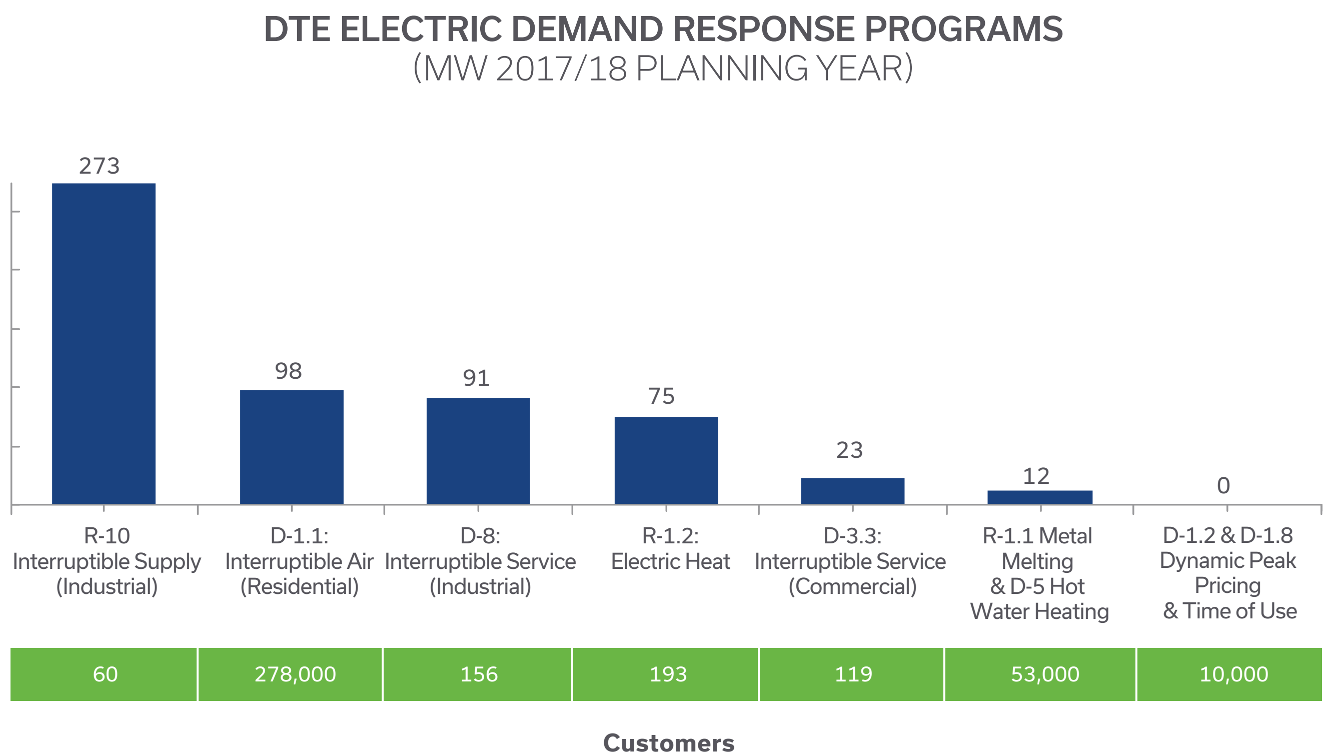
Interruptible Supply Rider (Rider 10): Limited to 650 MW of enrolled load, Rider 10 allows customers to elect the amount of interruption they are willing to take in their business for a lower rate. Rider 10 is designed for customers of greater than 50 MW at a single location, but at DTEE's discretion and with available capacity, the minimum site requirements can be waived.

Capacity Release (Rider 12): Customers can be provided a voluntary capacity release payment by subscribing 50 percent of their facility to the tariff. The capacity release payment is a mutually negotiated rate between the customer and DTEE. Customers must be greater than 250 kW at a single location to participate.

Dispersed Generation (Rider 13): Available to customers with on-site generation of greater than 250 kW at a single location. The customer and DTEE can mutually negotiate a contract price for which the customer will run their on-site generation during peak events.

The total of the demand response programs operated by the Company is 572 MW, as shown in Figure 6.10.4-1.

Figure 6.10.4-1

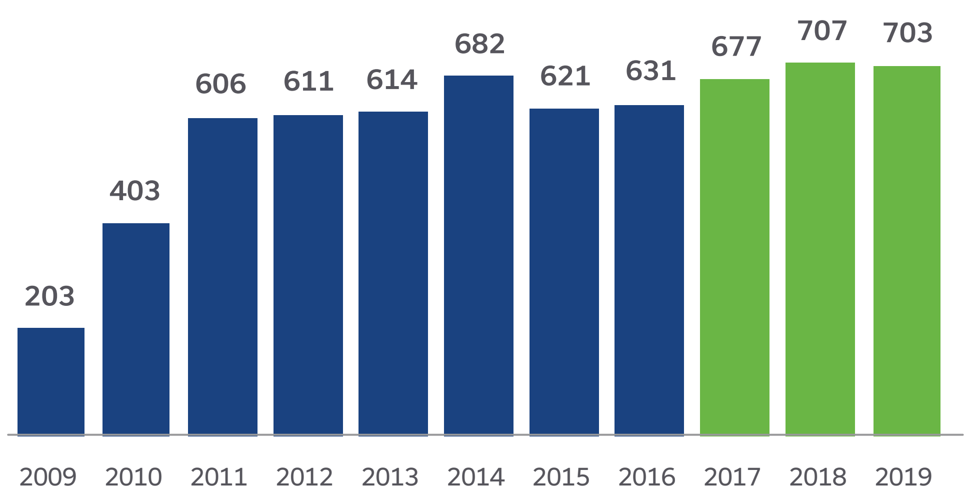


6.11 Energy Efficiency

Current Status

DTEE's energy efficiency program launched in June 2009 as a result of the Clean, Renewable and Efficient Energy Act, also known as 2008 PA 295. In 2016, PA 342 was signed into law, amending PA 295. The energy waste reduction standards in PA 342 maintain the minimum energy savings standards developed in PA 295 through 2021. DTEE's energy efficiency programs are designed to help reduce customers' energy use by increasing customer awareness and use of energy saving technologies, and by providing products and services such as rebates, tips, tools, strategies, and energy efficiency education to help customers make informed energy saving decisions. DTEE has continued to build on its momentum from the 2009 launch by enhancing the scope of existing programs and adding new program options to the portfolio. DTEE's energy efficiency program has consistently exceeded savings targets and is expected to continue that trend through the future, as shown in Figure 6.11-1.

Figure 6.11-1: Summary of Energy Efficiency Savings (GWh)



DTEE's ability to run the programs effectively has continued to improve through further maturity of systems and back-office processes. DTEE is currently engaged in evaluating new programs, delivery, and results as it continues to evolve the energy efficiency portfolio.

General Benefits of Energy Efficiency

Energy efficiency programs have several benefits, including savings from avoided cost of new generation capacity, non-electric benefits such as water and fossil fuel savings, environmental benefits, economic stimulus, job creation, risk reduction, and energy security. Energy efficiency programs help reduce the Company's reliance on fossil-fueled generation from existing plants and mitigate the need to build new generation resources in the future, help reduce reliance on power purchases from other suppliers, and ease utility bill pressures, providing benefits to consumers and the DTEE system.

At the consumer level, energy efficient products often cost more than their standard efficiency counterparts, but this additional up-front cost is balanced by lower energy consumption and lower energy bills. Over time, the money saved from energy efficient products may pay consumers back for their initial investment, as well as save them money on their electric bills. Although some energy efficient technologies are complex and expensive, such as installing new high efficiency windows or a high efficiency boiler, many are simple and inexpensive. Installing light emitting diode (LED) lighting or low-flow water devices, for example, can be done by most individuals.

6.11.1 ENERGY EFFICIENCY PROGRAM OFFERINGS

Energy efficiency programs include offerings available to Residential customers, Commercial and Industrial customers, pilot programs, and general education and awareness programs. In addition, the Evaluation, Measurement, and Verification (EM&V) function verifies net energy savings reported by the energy efficiency programs. The programs are managed by DTEE program managers and operated by expert implementation contractors, primarily utilizing local labor and products.

Each program offers a combination of energy efficiency products, customer incentives or rebates, and education. The program categories are:

- Residential Programs offer homeowners products, services and rebates encompassing appliance recycling; lighting; heating, ventilating and air conditioning (HVAC); weatherization; home energy assessments; low-income programs; energy education; and behavioral programs.
- C&I Programs offer businesses products; services, and prescriptive rebates for specific equipment replacement such as lighting, boilers, pumps, and compressors; custom programs providing rebates per kilowatt hour (kWh) of electricity savings for a comprehensive system or industrial process improvement; and energy education and pilot programs.
- Pilot Programs focus on new and emerging experimental programs to fit longer-term program portfolio needs, test the cost-effectiveness of new technologies, and assess customer adoption of new technologies and market acceptance of existing technologies using new approaches.

- Education and Awareness Programs are designed to raise customer energy efficiency awareness to help save energy and to reduce energy costs. A secondary objective is to raise awareness of the DTEE websites and other social media, which provide channels for customers to engage in specific energy efficiency programs offered.

Refer to Figure 6.11.1-1 for a list of current programs offered in 2017.

Figure 6.11.1-1 Current Energy Efficency Program Offerings

RESIDENTIAL PROGRAMS	C&I PROGRAMS	EDUCATION & AWARENESS PROGRAMS	PILOT PROGRAMS
DTE Insight & Energy Bridge	Prescriptive	Residential	Residential
Appliance Recycling	Non-Prescriptive	Commercial & Industrial	Commercial & Industrial
Multi Family	Self-Direct	Employees	Energy Management Tools
Energy Efficient Assistance	Business Energy Consultants		
ENERGY STAR	Retrocomissioning		
HVAC & Water Heating	Mid-Stream Lighting		
Audit & Weatherization			
On-Line Energy Audit			
Home Energy Consultation			
Schools			
Home Energy Reports			

6.11.2 RESIDENTIAL PROGRAMS

DTEE offers a variety of residential programs.

Residential ENERGY STAR Products: This program consists of three elements. First, DTEE continues to increase the market share of qualified lighting products sold through retail sales channels by providing primarily upstream incentives to lighting manufacturers to decrease customer costs, and information and education to increase consumer awareness and acceptance of energy efficient lighting technologies. Eligible efficient lighting measures primarily consist of LED lamps. Second, DTEE offers customer rebates on qualified energy efficient appliances, such as ENERGY STAR clothes washers, room air conditioners, and dehumidifiers. Third, DTEE continues to offer midstream incentives to retailers for stocking, promoting, and selling efficient consumer electronics products.

Appliance Recycling: The Appliance Recycling program is designed to decrease the number of working yet inefficient refrigerators, freezers, room air conditioners, and dehumidifiers in use in the residential market. The recycling program focuses on producing cost-effective, long-term annual energy savings by educating customers on how much energy these inefficient appliances use, and provides rebates to encourage customers to dispose of their inefficient appliances in an environmentally safe manner.

Heating, Ventilation and Air Conditioning (HVAC): The HVAC program is designed to provide incentives to customers who choose to purchase qualifying equipment. DTEE plans to offer incentives to customers for products such as central air conditioners, heat pumps, and electronically commutated motors. The HVAC dealers and contractors will continue to be leveraged since this network is a vital delivery channel for program participation. DTEE may also elect to use midstream incentives to HVAC dealers and distributors to stock, promote, and sell high efficiency heating and cooling equipment.

Multifamily: The Multifamily program is designed to generate energy savings by direct installation of low-cost energy efficient products. This program element provides multifamily residents with a quick and easy way to save energy. DTEE's implementation contractor trains and schedules equipment installers to retrofit living units in multifamily buildings. The contractor installs energy efficient water saving devices, including kitchen and bath aerators, and showerheads, and installs LEDs in each unit. As new technologies evolve, additional measures may be added if deemed cost effective. Educational information about the energy savings associated with these devices is left in these units. The directly installed measures are provided at no cost to property owners/managers and occupants. In addition to direct install measures, rebates may be offered for new or additional measures as opportunities are identified.

Home Energy Consultation (HEC): The HEC program is designed to provide customers with an in-home energy consultation as a starting point in becoming more energy efficient. The HEC customer experience is designed to provide energy efficiency education and awareness, and includes the direct installation of low-cost energy efficiency products (e.g., LEDs, hot water pipe wrap, and kitchen and bathroom faucet aerators) to help reduce energy use in their homes. The program also may connect customers with available payment assistance options, if needed, and help customers understand how to read a bill statement and how to access web-based information, such as DTEE's online energy audit tool. Besides the initial consultation, the program creates a personalized home energy report for the customer, providing the homeowner with information to take future energy efficiency actions (e.g., savings from measures installed, approximate savings if recommended measures are installed, how much energy each end use utilizes). Further, the program has been designed as an excellent vehicle for opening the door with a customer and starting a relationship centered on energy efficiency. If they choose, customers receive follow-up contacts (i.e., letters, emails, phone calls) to provide them with an opportunity to ask questions and receive further information on other energy efficiency programs.

Audit and Weatherization: The Audit and Weatherization program utilizes a couple of options for customers to learn about energy efficiency opportunities in their homes and encourages them to participate by providing: prescriptive weatherization rebates for customers who install qualifying measures, such as efficient windows and attic insulation; and encouragement to customers to complete projects that yield deep energy savings within their homes. Customers who prefer this program option may be required to obtain a comprehensive energy audit. The comprehensive audits enable a homeowner to schedule a home audit with a Building Performance Institute-certified auditor who will perform diagnostics of the building envelope, such as a blower door test and infrared imaging. The comprehensive audit allows customers to gain a better understanding of various energy efficiency improvements they can make to their homes.

School Program: The objective of this program is to provide energy education to students as a means to influence families' energy behaviors. The program currently targets students in 4th through 6th grades, who are provided with education and a take-home kit that raises awareness about how individual actions affect usage and provides low-cost products that can provide reductions in energy consumption. All educational materials and take-home efficiency kits are offered free of charge to the schools and their students.

Online Energy Audit: The Online Energy Audit program enables customers to use DTEE's energy efficiency website to complete a self-audit of their home, answer questions about their home, and receive valuable information and learn about ways that will help them save energy and money. Customers who complete the online audit receive a complimentary energy efficiency savings kit that contains low-cost energy savings products.

Behavior Program: The Behavior program seeks to change customer behavior and reduce energy usage through the delivery of home energy reports to randomly selected customers and/or the education and awareness provided through the DTE Insight application.

The home energy reports can display a comparison and trend analysis of customer energy usage to efficient and inefficient neighbors and target specific and relevant efficiency recommendations to these customers, making it easier for them to act on the recommendations and participate in the relevant programs. The DTE Insight application displays energy usage, allows for energy usage targets to be set, provides notification that the energy usage targets are being approached or have been surpassed, provides information about how to reduce energy usage, and encourages customers to reduce wasted energy.

Emerging Measures and Approaches Program: The Emerging Measures and Approach program in the residential portfolio encompasses measures that are mature or nearly mature from the pilot phase of program development. This program provides a transition point from pilots that have been successfully completed or are expected to be completed in the near future. This transition allows DTEE the opportunity to create an entry point for pilots before they are commercialized and incorporated into the mainstream programs.

Low Income: The objective of the program is to reduce the energy use of DTEE's low income homeowners through improvements to their existing home at no cost to them. In addition, the program aims to increase the installation of high efficiency equipment in low income rental properties. Low income customers traditionally reside in multifamily complexes and single family homes, and renting is common in this segment. The Low Income program will meet its objectives through the contribution of many programs:

- It continues to work with many partners, including local Community Action Agencies and nonprofit organizations to help eligible customers make energy-saving improvements to their existing homes at no cost through the Energy Efficiency Assistance program.
- It targets low income customers residing in single family homes through the HEC program.
- It targets low income multifamily properties through the multifamily program.
- It targets low income customers through its behavior program and the home energy reports.

DTEE continues to explore additional avenues beyond traditional delivery strategies to ensure the low-income community is fully served.

6.11.3 COMMERCIAL AND INDUSTRIAL PROGRAMS

DTEE offers a variety of commercial and industrial programs.

Prescriptive: The objective of this offering is to provide predetermined measures and incentives to C&I customers for the installation of energy-efficient equipment. These incentives are designed to encourage Commercial and Industrial business customers to install energy-efficient measures in existing facilities in an effort to reduce overall energy consumption and save money on their energy bills. Prescriptive categories of energy-efficient equipment for numerous applications include, but aren't limited to: lighting, controls, HVAC, refrigeration, and food service equipment. Incentives apply to qualified equipment commonly installed in a retrofit or equipment-replacement project and are paid based on the quantity, size, and efficiency of the technology.

Custom: This offering is designed to help C&I customers improve the efficiency of their existing facilities by offering incentives for installing non-standard energy-efficient equipment and controls in existing facilities that are not covered by the prescriptive Michigan Energy Measures Database (MEMD) measures. Non-

standard or non-prescriptive measures include: unique applications, equipment, or processes; applications in which operations vary so much by customer that standardized savings are difficult to calculate; and new technologies without established baseline savings. DTEE accounts for energy savings under this offering by approving and validating custom projects that are installed in a customer's facility. DTEE anticipates that the number of participants in the Custom offering may grow over time as business customers learn about the offering and are able to invest in tailored energy efficiency opportunities.

Request for Proposal (RFP): This offering provides customers who meet the RFP's requirements with custom incentives for installing innovative, non-standard energy-efficiency equipment and controls in existing facilities. This offering allows DTEE to increase its service territory's overall energy efficiency by accelerating projects with significant savings, reinvigorating certain stalled projects, and emphasizing specific types of extremely high efficiency technology or projects. This offering also provides DTEE with the ability to tailor specific product or market offerings to targeted segments and vertical markets to increase their participation. The RFP is designed to promote large capital intensive projects that may span more than one program year and to assist in reducing the customer's hurdles to achieve an acceptable payback period for the project.

New Construction: The New Construction and Major Renovation Incentive is intended to encourage the decision-makers in new construction/major renovation projects for non-residential customers to incorporate greater energy efficiency into their building design and construction practices. New construction/major renovations projects must involve facility improvements that result in measurable or verifiable electrical savings (kWh) exceeding the requirements set forth in American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Standard 90.1-2007, LEED, or local building codes, whichever is more stringent. The New Construction/Major Renovation Program offers incentives in three different areas:

- LEED Design Review Assistance
- New Construction Systems Approach
- New Construction LEED Whole Building Approach

Business Energy Consultation (BEC): The Business Energy Consultation offering is targeted at small business customers. It provides customers with a path to energy savings and a means of beginning their energy efficiency journey. A BEC starts with an energy assessment of the customer's facility. The energy assessment provides a detailed check of the customer's building, analyzes the energy envelope, checks for equipment that may not be operating properly, and inspects and assesses the heating and cooling, hot water and lighting systems. A final energy assessment report is provided to the customer detailing the findings and providing them with energy efficiency improvement recommendations. Additionally, a customer who opts to have a BEC completed could be provided direct install measures such as LED exit sign, Parabolic Aluminized Reflector (PAR) LED lamps, and a Tier 1 programmable thermostat.

Midstream Lighting: The Midstream Lighting offering is a simplified marketing approach that is targeted at lighting distributors. Partnering with the lighting distributor channel allows for flexibility and greater market insight. Customers and trade allies go to their lighting distributor to better understand the various technical applications of the ever-changing lighting market. These knowledgeable market experts generally cater to specific market segments and product types. By targeting the lighting distributor channel, DTEE can focus on fewer players who can affect many more downstream customers. Midstream programs are anticipated to change the distributor channel product stocking habits to include a higher percentage of energy efficiency lighting products. The Midstream Lighting offering has a firm product mix of only LED products such as: A Line and PAR lamps, 2- and 4-foot linear tube, wall mounted, exterior wall packs, and occupancy sensors. All midstream lighting products are LED and must be Design Lighting Consortium (DLC) verified and listed. Successful midstream programs leverage the distributor expertise to build a relationship of understanding and trust to motivate trade allies to stock and upsell the premium energy efficient equipment, which will increase the market share of LED products.

Retro Commissioning (RCx): Retro Commissioning is a systematic process to improve an existing commercial and institutional facility's building performance. Using a whole building systems approach, Retro Commissioning seeks to identify operational improvements that will save energy and increase occupant comfort. RCx consists of four phases: in the planning phase, the building systems to be analyzed are identified; the next phase determines how those systems are supposed to operate and a prioritized list of operating deficiencies is prepared; during the implementation phase, the highest priority deficiencies are corrected and proper operation is verified; in the verification phase, the hand-off process, improvements are reported and facilities executives are shown how to sustain proper operation. Retro Commissioning can be one of the most cost-effective means of improving operational energy efficiency in commercial buildings.

Emerging Measures and Approach Program: The Emerging Measures and Approach program in the C&I portfolio encompasses measures that are mature or nearly mature from the pilot phase of program development. This program provides a transition point from pilots that have been successfully completed or are expected to be completed in the near future. This transition allows DTEE the opportunity to create an entry point for pilots before they are commercialized and incorporated in to the mainstream programs.

6.11.4 HISTORICAL ENERGY EFFICIENCY PERFORMANCE

Since its inception in 2009, DTEE's energy efficiency programs have resulted in the first-year energy savings, first-year capacity savings, and spend detailed in Table 6.11.4-1.

Table 6.11.4-1 Historical First-year Energy Savings, Capacity Savings and Spend (2009-2016)

Year	Energy Savings (MWh)*	Capacity Savings (MW)*	Spend ($MM)
2009	202,718	19	$20
2010	402,995	46	$41
2011	605,572	69	$56
2012	610,655	80	$70
2013	613,528	84	$75
2014	682,000	97	$85
2015	621,721	81	$87
2016	630,920	98	$89

*Verified Net

The historical energy efficiency performance results displayed in Table 6.11.4-1 included EM&V activities. This work is performed by an independent EM&V contractor and must be performed to industry standards and guidelines developed by the Evaluation Workgroup of the MPSC Energy Waste Reduction Collaborative. EM&V activities are implemented through third-party contractors selected through a competitive bid process to verify program savings outcomes and monitor program performance. These activities serve to determine the actual program level savings being delivered and to maximize energy efficiency investments. Verified net energy savings are DTEE's reported savings after they have been adjusted based on the application of Installation Rate Adjustment Factors (IRAF) and Net-to-Gross Ratios (NTGR). Effective EM&V ensures that expected results are measurable, achieved results are robust and defensible, program delivery is effective in maximizing participation, and the overall portfolio is cost-effective.

6.11.5 NEAR-TERM FORECAST OF ENERGY EFFICIENCY

PA 342 as passed in December 2016 establishes a minimum energy savings requirement of 1.0 percent of total annual retail sales per year through 2021. DTEE is expecting an energy efficiency program that delivers annual energy savings of 1.5 percent through 2021, exceeding the minimum energy savings requirement. DTEE's 2018-2019 energy efficiency plan is fully described in the Michigan Public Service Commission Case No. U-18262. The first-year energy and capacity savings for DTEE's 2017-2021 energy efficiency programs includes the forecasted amounts shown in Table 6.11.5-1.

Table 6.11.5-1: Forecasted First-year Energy Savings, Capacity Savings and Spend (2017-2021)

Year	Planned Energy Savings (MWh)	Planned Capacity Savings (MW)	Spend ($MM)
2017	677,463	80.7	$93
2018	706,536	74.4	$102
2019	702,666	74.8	$103
2020	702,547	75.3	$104
2021	700,016	75.6	$105

Table 6.11.5-1 demonstrates that DTEE's forecasted spend for its 2017-2021 energy efficiency programs may remain consistent with previous spend amounts at approximately two percent of total electric retail sales revenue from the prior year. DTEE believes this level of energy efficiency spend is reasonable and prudent and allows DTEE to exceed the legislative savings target in a cost-effective manner. Cost-effectiveness is measured by the results of the Utility Cost Test (UCT) as established in PA 342. If the savings can be delivered at a UCT benefit-cost ratio greater than 1.0, then the energy efficiency plan is considered a good investment of ratepayer funds. DTEE's energy efficiency modeling for 2017 through 2021 forecasts a UCT benefit-cost ratio of approximately 6.0. Comparativelyv, The UCT for DTEE's 2018-2019 electric energy efficiency portfolio is forecasted to achieve a UCT benefit-cost ratio of 6.2 and is fully described in the Michigan Public Service Commission Case No. U-18262.

Forecasting for the next four years (2017-2021) of energy efficiency programs is similar to the previous planning processes DTEE used in preparing its previous energy efficiency plans. However, given more than eight years of experience with these programs, some areas have been developed with more depth. DTEE's planning process involves four steps. The first step is to develop an initial program by program measures mix built on experience and market feedback, as well as future capabilities and savings goals. The second step involves estimating program size parameters: a minimum and maximum range of units per year by sector. The third step involves optimizing the program portfolio mix to reflect a portfolio that best meets the cost and energy savings objectives. To optimize the portfolio, DTEE uses an Excel-based linear programming model, in which real-world constraints such as energy savings potential and costs are input along with historical and forecasted operational data. The model then optimizes the energy savings while satisfying the constraints. Finally, the output derived from the previous three steps is analyzed through the Demand-Side Management Option Risk Evaluator (DSMore) cost analysis tool to calculate cost-effectiveness. DSMore is a financial analysis tool designed to evaluate the cost-effectiveness, benefits, and risks of demand-side management programs, including energy efficiency.

Two major groups of inputs used in DSMore: the utility input assumptions and the program inputs. Utility input assumptions contain information that is specific to the utility and include items such as load shape, the commodity and non-commodity cost of electricity, customer energy rates, line losses, weather, and discount rates. Program inputs include energy savings, coincident peak demand reductions, incentive costs, program costs, evaluation, measurement and verification costs, education costs, and pilot costs.

6.12 Distributed Generation, Net Metering

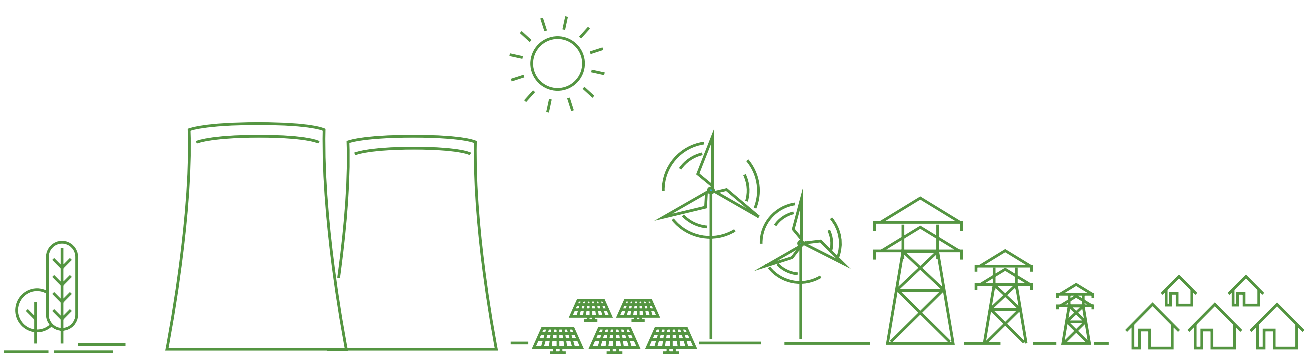
Through 2016, the Company had about 1,400 net metering sites with approximately 11.7 MW of installed capacity. Over 98 percent of installed net metering capacity is solar. Table 6.12-1 summarizes the total net metering sites and capacity as of the end of 2016, by category. Category 1 is limited to sites with renewable generation less than 20 kW of installed capacity; category 2 sites are limited to sites with renewable generation of more than 20 kW but less than 150 kW; category 3 is limited to methane digesters between 150 kW and 550kW. Table 6.12-1 also shows the percentage of the statutory cap each category has reached; category 1 is capped at 0.5 percent of the Company's peak; categories 2 and 3 are each capped at 0.25 percent of the Company's peak.

Table 6.12-1: Total Net Metering Sites and Capacity

	Sites	Capacity (MW)	Capacity Cap (MW)	Percent of Cap
Category 1	1,397	10.1	57.1	17.7%
Category 2	27	1.6	28.6	5.5%
Category 3	0	0	28.6	0.0%
Total	1,424	11.7	114.2	10.2%

SECTION 7

LOAD AND RESOURCE ANALYSIS



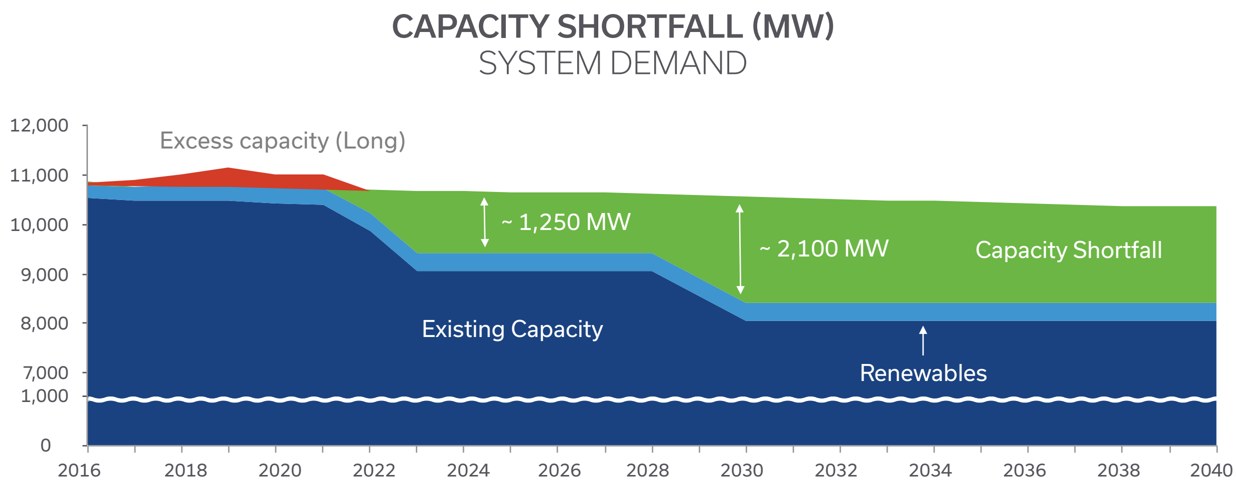
7 Load and Resource Analysis

DTEE's IRP process incorporates analysis and evaluation of the balance between load and existing resources including planned retirements, to determine whether there is a need for additional resources. Details in this section support the forecast that 2022 is the first year a substantial capacity shortfall may occur due to the planned retirement of the River Rouge, St. Clair, and Trenton Channel Power Plants in the early 2020s. Following 2022, the magnitude of the shortfall is projected to increase if DTEE does not act to address the gap between demand and resources with additional resources. This analysis will inform the decision on how much is needed and when.

7.1 Capacity Position Outlook

An integral part of the IRP process is to develop the Company's capacity outlook projection. A capacity shortfall is recognized in 2022. In the years after 2022, the shortfall magnitude is projected to increase, reaching as high as 1,300 MW before 2028. The capacity shortage is a result of the projected retirements of River Rouge in 2020 and St. Clair and Trenton Channel power plants in 2022 and 2023. In 2029, there is another significant increase in the projected shortfall amount when the potential retirement of Belle River power plant occurs. Due to the load and resource analysis indicating a significant gap between DTEE's demand and resources, DTEE must act. The capacity outlook between 2016 and 2040 is displayed in Figure 7.1-1, and represents the Company's forecast based on the original Reference scenario; it does not reflect the most recent resource and planning requirement changes utilized in the 2017 Reference scenario explained in more detail in Section 12.

Figure 7.1-1: 2016-2040 Capacity Outlook



7.2 Capacity Shortfall Computation

To determine whether there is a need for additional resources, the total Planning Reserve Margin Requirement (PRMR) was compared to the total planning resources. Under the MISO Resource Adequacy construct, MISO sets an annual capacity requirement for load serving entities based on their peak demand forecast coincident with the MISO peak plus a planning reserve margin (PRM). The PRM is based on the unforced capacity (UCAP) rating of capacity resources and is referred to as "PRM_{UCAP}." In simpler terms, demand (load) must be balanced with supply (resources). If the two are unbalanced, there is either an excess of capacity and supply is greater than demand, or there is a capacity shortfall and demand is greater than supply.

The first component needed for the PRMR calculation was the DTEE bundled non-coincident peak load forecast, which does not include the load of alternative electric suppliers (AES). It is the responsibility of AES or their designated market participant to provide planning resources to cover retail open access demand, including planning reserve margin. The next step was to apply the MISO coincident factor to the peak demand forecast resulting in the bundled coincident peak demand. Then the PRM_{UCAP} (published in the MISO 2016 Loss of Load Expectation (LOLE) Study) and transmission losses were applied to this adjusted peak demand value, resulting in the total planning requirement for the Company. The forecasted PRMR for planning year 2022 is shown in Table 7.2-1.

Table 7.2-1: PY 2022 Planning Reserve Margin Requirement

MW	PY2022-2023	PY2023-2024
Forecasted Bundled Non-Coincident Peak Demand	10,385	10,364
Coincidence Factor	0.96	0.96
Forecasted Bundled Coincident Peak Demand	10,013	9,993
Minus 2.2% Transmission Losses	220	220
Adjusted Peak Demand	**9,793**	**9,773**
Applied Transmission Losses (2.2%)	220	220
Planning Reserve Margin Requirement UCAP Basis	7.3%	7.30%
Planning Reserve Margin UCAP Basis	731	729
Adjustment for PRM and Transmission Losses	**951**	**949**
Total Planning Reserve Margin Requirement (PRMR)	**10,744**	**10,722**

The next step in determining a potential shortfall was to calculate the total UCAP of planning resources: the sum of the available capacities of owned generating units, demand-side management resources such as demand response (grossed up for transmission losses and PRM_{UCAP}), and purchase power agreements. The UCAP associated with each planning resource is determined by MISO according to its designated resource type. For example, non-intermittent generation resources (which make up most of DTEE's planning resources) are accredited by applying a forced outage rate (Equivalent Forced Outage Rate demand, EFORd) to the installed capacity (ICAP) of a particular resource. Wind resources, which are characterized as dispatchable intermittent generation resources, are accredited using an effective load carrying capability methodology. That is, the amount of wind required to satisfy established reliability criteria is determined using a probabilistic analysis, and is then distributed to the various wind nodes according to historical unit performance during peak times. A 50 percent capacity credit is applied to new solar resources. Capacity credit for solar will reflect historical operation once it has been established. By subtracting the total planning resources UCAP from the PRMR, the capacity shortfall or surplus was determined. In the case of DTEE's capacity outlook projection for integrated resource planning, 2022 is the first year a substantial capacity shortfall is forecast. The total planning resources and capacity position is shown in Table 7.2-2. A summary of all the years is shown in Table 7.2-3.

Table 7.2-2: PY 2022 Total Planning Resources and Capacity Position

MW	PY2022-2023	PY2023-2024
Generation Resources - Owned, Non-Intermittent	9,057	8,230
Owned, PA295	159	175
Total Company Owned Generation	9,215	8,405
Demand Response Programs	784	784
Plus 2.2% Transmission Losses and PRM $_{UCAP}$	74	74
Total Qualified Demand Response Resources	858	858
PPA, In-State Intermittent Resource	93	93
PPA, PURPA (BTMG)	106	100
Total PPA	**199**	**193**
Total Planning Resources	**10,272**	**9,456**
Capacity Position - Surplus / (Shortfall)	**(472)**	**(1,266)**

Table 7.2-3: 2016-2040 Assessment of Existing Resources vs. Demand Forecast

(a)	(b)	(c)	(d)	(e)	(f)	(g)
Year	Forecasted Non-Coincident Peak (MW)	PRM UCAP %	PRMR (MW)	Supply Side Resources UCAP (MW)	Demand Side Resources UCAP (MW)	Capacity Position Surplus/ **(Shortfall)** (MW)
2016	10,515	7.60%	10,919	10,127	710	**-83**
2017	10,408	7.50%	10,788	10,234	757	203
2018	10,454	7.40%	10,826	10,286	789	250
2019	10,453	7.40%	10,825	10,429	821	425
2020	10,435	7.30%	10,796	10,227	838	269
2021	10,412	7.30%	10,773	10,251	858	336
2022	10,385	7.30%	10,744	9,414	858	**-472**
2023	10,364	7.30%	10,722	8,598	858	**-1,266**
2024	10,347	7.30%	10,705	8,537	858	**-1,311**
2025	10,337	7.20%	10,685	8,552	858	**-1,274**
2026	10,333	7.20%	10,680	8,552	858	**-1,270**
2027	10,316	7.20%	10,663	8,551	858	**-1,253**
2028	10,298	7.20%	10,644	8,549	858	**-1,237**
2029	10,277	7.20%	10,623	8,054	858	**-1,711**
2030	10,255	7.20%	10,600	7,541	858	**-2,201**
2031	10,230	7.20%	10,574	7,526	858	**-2,190**
2032	10,204	7.20%	10,547	7,526	858	**-2,163**
2033	10,177	7.20%	10,519	7,507	858	**-2,154**
2034	10,159	7.20%	10,501	7,507	858	**-2,135**
2035	10,138	7.20%	10,479	7,507	858	**-2,113**
2036	10,114	7.20%	10,454	7,506	858	**-2,090**
2037	10,087	7.20%	10,426	7,506	858	**-2,063**
2038	10,059	7.20%	10,397	7,506	858	**-2,033**
2039	10,061	7.20%	10,399	7,504	858	**-2,037**
2040	10,062	7.20%	10,400	7,504	858	**-2,038**

7.3 Reliability

The determination of the PRM through MISO processes is designed to meet established reliability requirements. The PRM is calculated through a Loss of Load Expectation (LOLE) study to allow the MISO footprint to maintain reliable operation while encompassing unforeseen events, such as unexpected generation outages or extreme weather events. Load Serving Entities (LSEs) maintain an obligation to procure planning resource capacity equal to their PRMR either through the annual auction or by utilizing a Fixed Resource Adequacy Plan (FRAP). Alternatively, LSEs can reduce their PRMR by electing to pay the Capacity Deficiency Charge, equal to 2.748 times the Cost of New Entry (CONE).

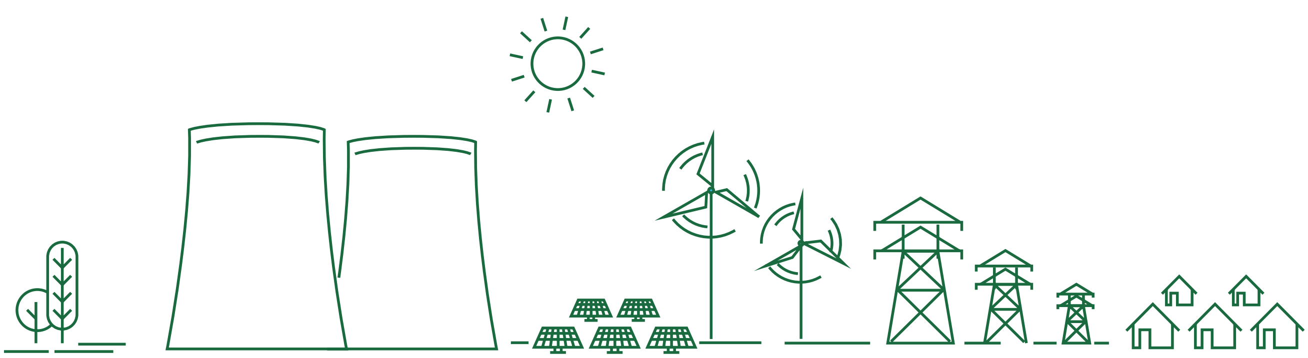
Additionally, MISO has established Local Resource Zones (LRZs) (DTEE's service territory is in Zone 7) to ensure that adequate capacity resources are physically located in portions of the MISO region to reliably serve load. Each LRZ must physically contain sufficient capacity resources to meet the Local Reliability Requirement (LRR) while fully utilizing the Capacity Import Limit (CIL). The difference in LRR and CIL—the amount of capacity resources that must be physically located in a particular LRZ—is referred to as the Local Clearing Requirement (LCR).

Insufficient capacity resources for either the MISO footprint (inadequate resources to meet PRMR) or for a particular LRZ (inadequate resources to meet LCR) will result in the annual Planning Resource Auction clearing at CONE. This price signal indicates that the market is deficient of capacity resources and new entry is required.

DTEE complies with its tariff obligations by participating in the annual MISO Planning Resource Auction. All DTEE resources are physically located within LRZ 7, which also contains the entirety of DTEE's service territory.

SECTION 8

TRANSMISSION AND DISTRIBUTION



8 Transmission and Distribution

Securing energy resources to meet demand is not the only requirement for serving customers. Integrated resource planning must address delivery and reliability as well. Currently, MISO is responsible for providing transmission services to DTEE. DTEE has a Distribution Investment and Maintenance plan to provide safe, reliable, and affordable electricity to its customers by balancing three objectives on its distribution electric grid: reducing risk, improving reliability, and managing costs.

8.1 MISO Overview and Transmission Service

In 2003, DTEE sold its transmission system to ITC. DTEE is classified as a Generator Owner and a Load Serving Entity. ITC is now the transmission planner and transmission owner and develops long-term plans for the reliability and adequacy of the interconnected bulk electric transmission system for Michigan. ITC subsequently joined MISO, at which time functional control of the transmission system was turned over to MISO. As a result, MISO became the transmission provider responsible for providing transmission service to DTEE.

MISO is a multi-state Regional Transmission Organization under the jurisdiction of the Federal Energy Regulatory Commission. Under a FERC-approved rate schedule, MISO provides regional grid management and open access to the transmission facilities under MISO's functional supervision. This grid management includes the operation and planning of the transmission systems. MISO has functional control of the regional transmission system. The MISO Transmission Expansion Plan (MTEP) proposes transmission solutions to meet transmission needs efficiently and reliably to deliver the lowest-cost energy to customers in the MISO region. In addition, transmission adequacy is the primary consideration in MISO's annual loss of load expectation (LOLE) studies. MISO engages with stakeholders through a comprehensive planning process spanning 15 months. This process provides transmission owners (TOs) a forum to propose needed reliability, load interconnection, and asset renewal projects and to move existing projects forward. In addition, the process provides a forum for stakeholders' input on the proposed projects, allowing MISO staff to independently evaluate TOs' project proposals and recommend projects for approval by the MISO board of directors.

MISO provides a forum that is transparent and encourages feedback from all stakeholders to ensure that the projects are scrutinized properly and that they provide the best value to Michigan's customers. DTEE, as one of the stakeholders, is actively engaged in this process and provides feedback and alternative solutions to various projects through the MTEP process. DTEE uses the software and processes identified by MISO to study generation interconnection projects and proposed transmission expansion projects in the MTEP process. These studies are used to identify whether thermal overloads or voltage problems exist for the normal system, as well as for single contingencies or double contingencies as identified by the North American Electric Reliability Corporation (NERC) or ITC planning criteria. DTEE also participates in MISO committees such as the Planning subcommittee, the Modeling Users group, and Planning Advisory Committee. Transmission improvements are intended to lead to cost-effective solutions for LSEs and their customers.

DTEE requests transmission service under Module B of the MISO Energy and Operating Reserves Tariff (MISO Tariff). DTEE may request either point-to-point transmission service (PTP) or Network Integration Transmission Service (NITS). PTP service allows DTEE to schedule a transaction between two points; NITS is a transmission service that allows DTEE to utilize its designated generation resources (as well as other non-designated Generation Resources) to serve its network load located in the ITC pricing zone.

MISO evaluates requests for PTP and NITS and grants service based on available transmission capacity. DTEE has contractual agreements with MISO and requests transmission service via MISO's Open Access Same-Time Information System (OASIS), an internet-based system. The Company pays for these transmission services pursuant to the appropriate rates and schedules in MISO's Tariff approved by the FERC. DTEE currently has 11,847 MW of yearly (long-term) firm NITS transmission reservation. The Company has no long-term PTP transmission reservation.

Based on an analysis of the transmission import capability performed by HDR, as well as the current MISO LOLE report, it is unlikely that the import capability of the transmission system into the lower peninsula of Michigan could be expanded to offer a realistic alternative to the proposed project of a 2x1 CCGT. Retirements will continue in DTEE's service territory as well as in neighboring utilities, increasing the need for new generation.

8.2 Distribution Investment and Maintenance Plan

The Distribution Investment and Maintenance Plan was developed to achieve three objectives for DTEE customers: reduce risk, improve reliability, and manage costs. The plan consists of five focus areas: preventive maintenance, tree trimming, infrastructure resilience, infrastructure redesign, and technology enhancements.

- Preventive maintenance: inspecting equipment on a regular basis to minimize equipment failures and maximize its useful life with minimum lifecycle costs.
- Tree trimming: trimming trees to enhanced clearance specifications to minimize tree interference with the electrical system, improve reliability, and reduce trouble and wire down events caused by trees.
- Infrastructure resilience: improving the condition of specific asset classes or addressing known asset or system issues (e.g., system cable replacement).
- Infrastructure redesign: redesigning substations and circuits to manage design obsolescence and improve conditions of multiple asset classes.
- Technology enhancements: leveraging technology to improve grid operability and flexibility to integrate distributed energy resources.

Figure 8.2–1 illustrates the DTEE Distribution Investment and Maintenance Plan framework.

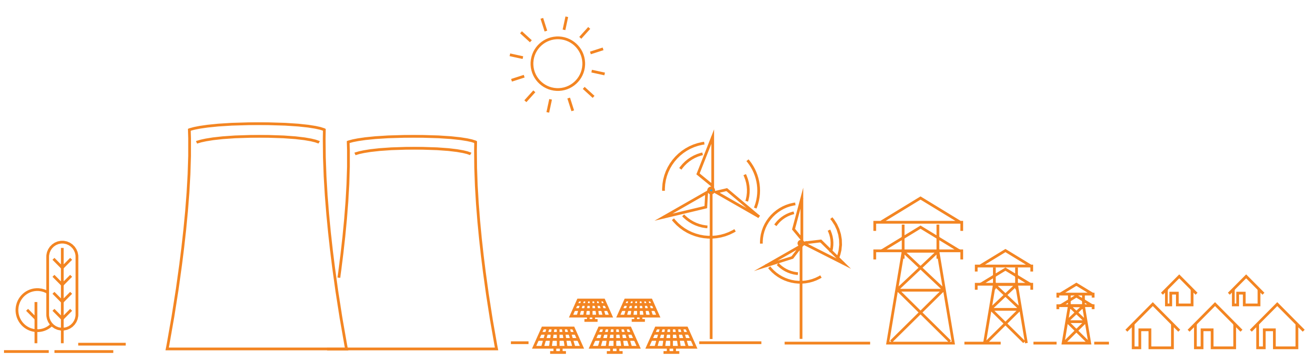
Figure 8.2-1: DTEE Distribution Investment and Maintenance Framework

INVESTMENT AND MAINTENANCE FOCUS AREAS	**Preventative Maintenance**	**Tree Trimming**	**Infrastructure Resilience**	**Infrastructure Redesign**	**Technology Enhancement**
INVESTMENT AND MAINTENANCE PROGRAMS	Various preventative maintenance programs based on recommended inspection cycles, and condition Based Maintenance	Tree trimming the circuits to enhanced specification and reclaim right of way on circuit backbones	• Circuit renewal • CEMI program • System Resiliency • Secondary/Service improvement • Capital replacement • Pole/Pole Top Maintenance	• Capacity planning and load relief • Substation outage risk mitigation and reduction • 4.8V/8.3kV consolidation and conversion	• Line sensors • ADMS/SOC modernization • SCADA monitoring • Cyber security • System Automation • AMI upgrade • DER application • Technology pilot
KEY ENABLERS	Industry Benchmarking Workforce Planning Capital Plan and Capital Project Approval Distribution Design Standards Replacement Unit and Spare Part Management				
DISTRIBUTION OPERATIONS OBJECTIVES	DTE Electric provides safe, reliable, and affordable electricity to its customers and ensure superior customer satisfaction • Reducing risk • Improving reliability • Managing costs				

Through successful execution of the Distribution Investment and Maintenance Plan, DTEE can deliver maximum customer benefits and provide a modern electric distribution system that meets that needs of the 21st century economy.

SECTION 9

ENVIRONMENTAL STEWARDSHIP AND COMPLIANCE



9 Environmental Stewardship and Compliance

DTEE has a long history of environmental conservation and stewardship, and is committed to protecting its communities, employees, and customers. In May 2017, DTEE— a leader in technologies to reduce emissions—announced a long-term sustainability and carbon reduction initiative to reduce CO_2 emission by 80 percent by 2050. DTEE will accomplish this by using more natural gas, wind, and solar, and by improving customers' energy saving options. The plan for reducing DTEE's CO_2 emissions makes business sense, ensures safe, reliable, affordable, and cleaner energy for its customers, and allows the Company to implement a long-term generation transformation strategy in which more than half of its energy is generated from zero-emitting sources. DTEE operates in a manner that complies with or exceeds numerous federal, state, and local environmental regulations, rules, standards, and guidelines, which are described in this section.

9.1 Environmental Stewardship

DTE Electric works to take care of the land, water, and living creatures within its service territory and beyond. The Company maintains thousands of acres of land in its natural state, which provide habitat for hundreds of species of birds, mammals, fish, and insects. DTE has 36 sites, including all the DTEE power plants, certified under the Wildlife Habitat Council, a nonprofit organization that helps companies manage their property for the benefit of wildlife. All the DTEE power plants are also ISO 14001 third-party certified. The ISO 14001 standard sets criteria for a company's environmental management system, a set of processes for managing environmental programs. DTEE's system includes employee training, risk assessment, monitoring, auditing, and periodic recertification. For DTEE, environmental stewardship starts with operating its facilities, land, and equipment in a manner that complies with or exceeds governmental standards and is protective of its employees, customers, and surrounding communities, while maintaining affordable service.

Photos: A bald eagle at DTEE Monroe Power Plant and restored shoreline at DTEE River Rouge Power Plant

The electric power industry across the U.S. is undergoing a major transformation as the country seeks lower-carbon energy sources. DTEE is an industry leader in this transformation and recognizes its responsibility to conserve the finite natural resources that are available. DTEE is committed to environmental compliance and stewardship and protecting the land, water, and air. DTEE is transforming the way it supplies energy, using more natural gas, wind, and solar. As the Company moves toward cleaner energy sources, it remains focused on maintaining reliability and affordability for its customers. Recently, DTEE announced a broad sustainability initiative that will reduce the Company's carbon emissions: 30 percent reduction by the early 2020s; 45 percent by 2030; 75 percent by 2040; and more than 80 percent by 2050. DTEE will achieve these reductions by incorporating substantially more renewable energy, transitioning its fuel from coal to natural gas, continuing to operate its zero-carbon emission Fermi 2 power plant, and strengthening options for customers to save energy and reduce costs. DTEE will continue to be at the forefront of emissions reductions while being mindful of its customers' needs for affordability and reliability, all of which are considered in the Company's integrated resource planning.

DTEE's environmental compliance includes completed environmental retrofits for existing plants to operate in compliance with all applicable regulations while the plants are in operation. In 2014, installation of emission controls on all four units at Monroe Power Plant was completed. The $2 billion project to install emission controls at the plant included installation of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) equipment. This equipment reduces emissions of sulfur dioxide (SO_2), oxides of nitrogen (NO_X), particulate matter, mercury, acid gases, and other air pollutants. The project also allows the plant to comply with several air quality standards including the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS).

Photo: DTEE Monroe Power Plant

The MATS regulations instituted significant reductions in emission limits on mercury, acid gases, and hazardous air pollutants. To comply with MATS, the remaining coal plants installed a combination of dry sorbent injection (DSI) for acid gas control and activated carbon injection (ACI) for mercury control. These installations, totaling more than $200 million in investment, were completed in 2016. All remaining coal-fired power plant units comply with MATS.

Photo: DTEE Belle River Power Plant MATS control equipment

In addition to the installations and large expenditures for environmental compliance over the last several years, several regulations under the Clean Air Act (CAA), Clean Water Act (CWA), and the Resource Conservation and Recovery Act (RCRA) will affect coal-fired power plants in the coming years. The regulations have different implementation timelines and will have various outcomes for DTEE. Regulatory compliance and the effects of some of these regulations are discussed further in this section.

9.2 Environmental Compliance

9.2.1 NATIONAL AMBIENT AIR QUALITY STANDARDS

The CAA requires that the EPA set national ambient air quality standards (NAAQS) for six pollutants: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2). NAAQS are set by the EPA at levels deemed to be protective of public health and the environment. The standards are reviewed periodically and may be revised based on that review. Although all of the NAAQS affects DTEE's power plants, two in particular are currently involved with its generation fleet. In 2010, the EPA lowered the one-hour SO_2 NAAQS, which resulted in an area in southern Wayne County designated as non-attainment in 2013. This area included DTEE's River Rouge and Trenton Channel power plants. DTEE implemented significant SO_2 emissions reductions at both power plants to maintain attainment in the area.

The same 2010 SO_2 NAAQS that affected the Wayne County plants also affects the future operation of the Belle River and St. Clair power plants in St. Clair County. An area of St. Clair County that includes the two DTEE power plants was designated as non-attainment in late 2016. DTEE is working with MDEQ on developing a plan to achieve attainment, while minimizing expense to its customers and maintaining reliable and efficient energy production in the area.

The ozone NAAQS was lowered from 75 parts per billion (ppb) to 70 ppb in 2015. Several ozone monitors in southeast Michigan showed ozone levels above the 70 ppb standard, which precipitated MDEQ to recommend a non-attainment designation of a large area of DTEE's service territory, in which all of DTEE's coal-fired power plants are located. Though the EPA has yet to take action on finalizing the non-attainment area recommendation, DTEE will work collaboratively with the state to develop a state implementation plan (SIP) as required. Plant retirements within the non-attainment area will reduce emissions that contribute to the formation of ozone.

9.2.2 CROSS-STATE AIR POLLUTION RULE

The Cross-State Air Pollution Rule (CSAPR) is the most recent EPA regulation targeting interstate and regional transport of air pollution. CSAPR replaces the Clean Air Interstate Rule (CAIR). Both rules are trading programs that establish limitations on SO_2 and NO_X emissions from electric utilities. CSAPR establishes emission allocations to each generating unit in a group of Midwestern states including Michigan. Through a phased approach, these allocations are reduced over time. Although the allocations are made at the unit level, CSAPR allows for emissions allowance trading among utilities covered by the rule. DTEE has been and remains fully compliant with CAIR/CSAPR.

In 2016, the EPA promulgated an update to the CSAPR aimed at reducing ozone transport to downwind states from the Midwestern states covered by CSAPR. The update drastically reduced the emissions allocations for ozone season (May through September). In addition, the update also restricted the amount of emissions credits that can be carried over from previous years. The most significant CSAPR-related effect on DTEE going forward is ozone season NO_X emissions. After the allocations in the update rule were made final, initial DTEE analysis showed that reductions from typical ozone season NO_X emissions from the Company's units will be required in 2017 and beyond.

9.2.3 CLEAN POWER PLAN

DTEE played a significant role in developing the federal clean energy rule known as the Clean Power Plan. The EPA finalized in August 2015 new source performance standards (NSPS) for existing power plants under Section 111(d) of the CAA as part of the CPP. The rules underwent significant legal challenges and are currently stayed by a 2016 U.S. Supreme Court decision. On March 28, 2017, an Executive Order was issued, which instructed the EPA to review the final rules. Regardless of the debate about the rule in the federal courts and the CPP stay, DTEE plans to reduce carbon by modernizing its fleet, investing in renewables, and implementing energy efficiency.

9.2.4 STEAM ELECTRIC EFFLUENT LIMITATION GUIDELINES (ELG)

In late 2015, the EPA issued its final rule related to wastewater discharge or ELG for steam electric power generators. These new requirements require additional controls to be installed with a compliance schedule ranging from December 31, 2018 to 2023. Under the ELG, the discharge of three wastewaters will be disallowed or severely limited: water from the sluicing of bottom ash, water from the sluicing of fly ash, and wastewater from the FGD wastewater treatment process. Sluicing is a process in which water is used to transport solid material through pipes to a collection point. Evaluation of these regulations along with plant age and other factors through the Company's IRP process has led to a more definitive time table for retiring River Rouge, St. Clair, and Trenton Channel Power Plants, as discussed in Section 6.3.

Under ELG regulations currently estimated to take effect by 2023, discharge of water from the sluicing of bottom ash would no longer be permitted, which would require either closed-loop recirculation or modification to a dry bottom boiler. This requirement affects all five coal-fired power plants within DTEE. In addition, discharge of water used to sluice fly ash would no longer be permitted. This part of the regulation affects only the Monroe Power Plant, as the other plants currently utilize dry fly ash transport. Monroe has already converted two of the four units to a dry ash system, and DTEE is currently evaluating a proposal to convert the remaining two units to dry fly ash handling, including adding redundancy and alternative designs. The final rule also established new, more stringent requirements for effluent discharge limits for arsenic, mercury, selenium, and nitrogen (nitrates and nitrites) in wastewater discharged from FGD systems. These requirements will affect only the Monroe Power Plant, DTEE's only plant with FGD. Technologies associated with FGD wastewaters are newer and fall into two general categories: biological and volume reduction. DTEE is currently evaluating several options for eliminating discharges of wastewaters from bottom ash and fly ash, as well as treatment of FGD wastewater. DTEE is also working with the Electric Power Research Institute (EPRI) to conduct a technology demonstration test with Monroe FGD wastewater. To comply with the current ELG regulations, DTEE would need to make significant capital investments at any facility that will operate beyond the compliance dates outlined in the rule. The ELG regulations are currently stayed and under review by the EPA; DTEE will monitor the rule status on an ongoing basis.

9.2.5 COOLING WATER INTAKE (316B)

The EPA finalized regulations on cooling water intake under Section 316(b) of the CWA in August 2014 for power plants and other facilities. In addition to the five coal-fired power plants affected by the 316(b) regulations, the Company's nuclear plant, Fermi 2, is also affected. DTEE plants currently use once-through cooling, which entails taking water in for cooling which is then discharged back to the body of water with no recirculation. The cooling water intake structures are equipped with screens which prevent debris from being taken into the plant systems. The regulations affect cooling water intake at existing facilities in two main areas: first, existing facilities are required to reduce fish impingement; second, existing facilities are required to conduct studies to determine whether and what controls would be required to reduce the number of aquatic organisms entrained by the cooling water system. The regulations also include requirements for new units that add electrical generation capacity.

DTEE is conducting the required studies to determine the best technology for reducing the environmental impacts of the cooling water intake structures at each of its facilities. Study reports will be submitted to MDEQ for their evaluation as part of the National Pollutant Discharge Elimination System (NPDES) permitting process, by the required dates. MDEQ will utilize Best Professional Judgement, on a site-specific basis, to determine which technologies, if any, may apply to DTEE facilities.

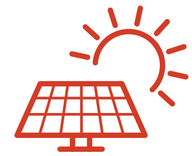
9.2.6 COAL COMBUSTION RESIDUAL RULE

The EPA's Coal Combustion Residual (CCR) Rule, which became effective in October 2015, broadly regulates all landfills and impoundments at DTEE's operating coal plants. The rule is based on the continued listing of coal ash as a non-hazardous waste and relies on various self-implementation design and performance standards. The rule also requires the closure of ash basins at the end of useful life of the associated power plants and requires ash-laden waters to be handled in steel and concrete tanks.

DTEE currently operates three ash landfills (Sibley Quarry, Range Road, and Monroe Power Plant vertical extension) and four surface impoundments (Belle River, St. Clair, and River Rouge bottom ash basins and Monroe Power Plant fly ash basin). Current CCR obligations at DTEE plants vary based on plant life. Regardless of the timing of plant closures, long-term ground water monitoring, potential mitigation, inspections, and reporting obligations will continue for many years.

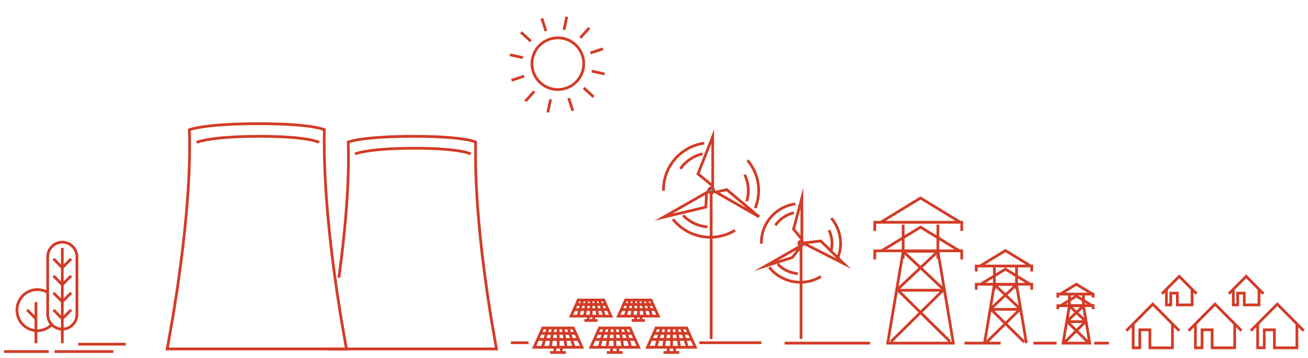
The EPA also revised the CCR rule in October 2016, reversing its earlier position, and now requires groundwater remediation at basins when groundwater standards are exceeded. This provision applies to the 100 acre Monroe Power Plant bottom ash basin. The new closure plan for this basin will not only take longer to implement, but will be driven by the results of the recently implemented groundwater monitoring program. Closure of this basin will likely be the most costly and longest term CCR remediation plan of the three DTEE basins.

Long-term work required by the CCR rule began even prior to the rule being finalized, with the first installations going into service in 2015. Work continued in 2016 and will continue into the foreseeable future. To achieve compliance with the multiple requirements of the CCR regulations, several initiatives are underway to ensure monitoring, segregation, and cap and closure requirements are in compliance at all plant sites by the dates stipulated in the rule. DTEE continues to evaluate compliance plans for all the affected landfills and impoundments.

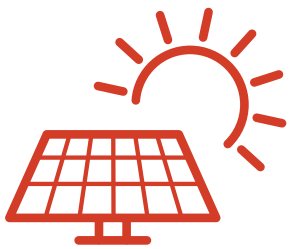


SECTION 10

FUTURE ALTERNATIVES



10 Future Alternatives



In the IRP process, selecting the optimum plan to meet future electric demand involves evaluating generation sources. HDR provided an engineering evaluation study[1] summarizing costs and performance parameters of supply-side power generation alternatives. These alternatives were supplemented with DTEE internal knowledge on renewable technology, energy efficiency, and demand response. The DTEE IRP team extended the evaluation with models based on risk, cost, and satisfying generation and capacity requirements. This section details DTEE's review of several potential resource additions, including natural gas, nuclear, coal-based alternatives, wind, solar, battery, and cogeneration.

10.1 Natural Gas Options

Power generation technologies that utilize combustion of natural gas broadly fall into two main categories: simple cycle generation and combined cycle generation. Natural gas generation technologies such as combustion turbine (CT) generators and reciprocating internal combustion Engines (RICE) are considered simple cycle. A combination of one or more combustion turbines in which turbine exhaust heat is used to generate steam in a heat recovery steam generator (HRSG) to power a steam turbine generator is known as combined cycle gas turbine or CCGT.

Natural gas alternatives that have been evaluated include: five simple cycle combustion turbine options consisting of four combustion turbines and one RICE configuration, and five combined cycle plant configurations. The simple cycle plants are typically used as peaking units with a nominal output ranging from 50 to 225 MW. The combined cycle units are typically used as intermediate to base loaded units with nominal output ranging from 350 to 1400 MW. Enhancements to combined cycle plant performance such as HRSG supplementary duct firing, which add to the unit's capacity, were also evaluated.

Original Equipment Manufacturer data was used to provide representative combustion turbine and RICE

1 For More details on the HDR Alternatives analysis study see Appendix E

performance and cost baselines for the natural gas generation technology alternatives. Numerous other manufacturers of this equipment with similar performance are available and will ultimately be evaluated and considered should new generation development be pursued. All alternatives considered in this report are currently commercially available; however, some have longer operating history than others and are proven technology in the field. Analyses performed on the natural gas alternatives were all based on the same site location.

Natural gas alternatives are known for their wide range in generating capability, flexible dispatch, and low costs of operation (lower staffing than existing coal plants). They have heat rates as low as 6,300 Btu/Kwh. In addition to having low emissions, natural gas alternatives can also be flexibly located and offer opportunities for modular construction and cost savings.

10.1.1 Simple Cycle Combustion Turbine

Simple cycle combustion turbine units are often used for peaking power needs. They have higher heat rates than combined cycle units but are typically capable of faster ramp-up times. The engineering, procurement, and construction (EPC) project schedule for simple cycle units is between 20 to 24 months from full notice to proceed to commercial operation. The emissions rate for CO_2 is 118 (lb/mmBtu) and NO_X is between 0.0162 and 0.0916 (lb/mmBtu). NO_X emissions for the simple cycle options assume that there are no added emissions controls. Combustion turbines consist of aeroderivative and frame type machines. The smaller of the two aeroderivative combustion turbine generator options has a nominal output of 50 MW. The larger of the two aeroderivative combustion turbine generator options has a nominal output of 100 MW. The smaller frame type combustion turbine generator has a nominal output of 100 MW. The larger frame type combustion turbine generator is the F-Class with a nominal output of 225 MW. The RICE was evaluated as a three-engine configuration. The benefits of the RICE include a smaller footprint, higher efficiency, and fast start times. Because RICE is a modular technology, it is costlier on larger scales than frame type combustion turbines. The characteristics of each simple cycle unit that was screened in the IRP modeling process are listed in Table 10.1.1-1. These are considered generic units and are used in modeling as representatives of technologies of certain sizes, operating characteristics, and costs. The intent was not to screen every gas unit on the market, but rather to screen enough to determine whether the alternative progresses further in the modeling process.

Table 10.1.1-1: Generic Simple Cycle Combustion Turbine Characteristics used in IRP modeling

	Smaller Aeroderivative CT	Aeroderivative CT	Frame-type CT	F-Class Frame-type CT	RICE
Unit Characteristics					
Summer Net Cap (MW)	36	93	83	228	54
Summer Net Plant Heat Rate (Btu/kWh)[1,4,5]	9,596	8,982	11,469	9,834	8,441
Tech Rating (developmental, mature, commercial)	Mature	Mature	Mature	Mature	Mature
Project Schedule (months)	24	24	24	24	20
Capital Cost ($/kW)[3]	1,942	1,599	1,175	917	1,273
First Yr Fixed O&M[2,5] ($/MW)	34,291	15,429	15,670	6,974	20,797
First Yr Variable O&M[2,5] ($/MWh)	3.69	4.07	8.73	6.02	5.75

Table Notes:

1. Heat Rate values expressed in higher heating value (HHV)
2. First-year fixed and variable O&M numbers computed without accounting for Transmission Network Upgrade costs (outside the fence)
3. Capital costs include owner costs, owner contingencies, and cost allocation for substation and natural gas site utilities
4. Summer heat rate and capacity include evaporative cooling
5. Performance and costs include wet cooling tower heat rejection
6. In the evaluation study, the units were dispatched at an annual capacity factor of 17 percent, to determine the O&M estimates.

10.1.2 COMBINED CYCLE GAS TURBINE

The configuration of a combined cycle unit considerably improves fuel efficiency over simple cycle units. EPC project schedule for these combined cycle units is between 36 to 42 months from full notice to proceed to commercial operation. The emissions rate for CO_2 is 118 (lb/mmBtu) and NO_X is 0.0072 (lb/mmBtu) for the generic units evaluated. NO_X emissions for combined cycle units are lower than simple cycle units due to reductions achieved with control equipment included in the heat recovery steam generator.

Two classes of 1x1 combined cycles were considered: the F-class and the H-class. The difference is that the H-class are considered advanced class and are newer technology than the F-class. The "1x1" nomenclature refers to the fact that there is one combustion turbine and one steam turbine. Likewise, a "2x1" would have two combustion turbines and one steam turbine. The 1x1 F-class has a nominal output of 350 MW. This is compared to the H-class 1x1 with a nominal output of 450 MW.

Two classes were also evaluated for the 2x1 machines. The F-class 2x1 has a nominal output of 700 MW, and the H-class 2x1 has a nominal output of 900 MW.

For the 3x1 option, only the advanced H-class 3x1 combustion turbine generator was evaluated with a nominal output of 1400 MW. A 3x1 F-class was not evaluated because the size is similar to a 2x1 H-Class.

For all combined cycle configurations, supplemental duct firing options are available. Duct firing is utilized to raise the exhaust temperature. This improves peak power production by enabling higher steam production. Duct firing does not improve cycle efficiency, and can in fact reduce the efficiency in certain configurations (e.g., if larger downstream equipment is needed to accommodate the extra steam). Various capacities of duct firing are available and depend on combustion turbine generator size. The amount of duct firing capability must be selected early in the design process to ensure full compatibility and integration with all plant equipment.

The characteristics of each combined cycle unit are listed in Table 10.1.2-1. Again, the operating characteristics in the table are representative of generic alternatives and encompass a wide range of sizes.

Table 10.1.2-1: Generic Combined Cycle Characteristics used in IRP modeling

	1x1 F-Class	1x1 H-Class	2x1 F-Class	2x1 H-Class	3x1 H-Class
Unit Characteristics					
Summer net Cap (MW)	345	478	691	959	1443
Summer Net Plant Heat Rate (Btu/kWh)[1,4,5]	6,546	6,366	6,525	6,348	6,333
Tech Rating (developmental, mature, commercial)	Mature	Commercial	Mature	Commercial	Commercial
Project Schedule (months)	36	36	36	36	42
Capital Cost ($/kW)[3]	1,199	1,144	1,129	1,055	987
First Yr Fixed O&M ($/MW)[2,5]	14,551	11,404	9,897	7,972	6,719
First Yr Variable O&M ($/MWh)[2,5]	1.51	2.51	1.44	2.47	2.40
Supplemental Firing – Incremental to net plant generation (MW)[7]	50	50	100	100	150

Table Notes:

1. Heat Rate values expressed in higher heating value (HHV)
2. First-year fixed and variable O&M numbers computed without accounting for Transmission Network Upgrade costs (outside the fence)
3. Capital costs include owner costs, owner contingencies and cost allocation for substation and natural gas site utilities
4. Summer heat rate and capacity include evaporative cooling
5. Performance and costs include wet cooling tower heat rejection.
6. In the evaluation study, the units were dispatched at an annual capacity factor between 70 percent and 80 percent, to determine the O&M estimates.
7. The amount of duct firing is a function of CTG size as well as CTG exhaust energy available based on specific project need. Values in table were used for modeling purposes.

10.2 Other Base Load Options: Nuclear and Coal Alternatives

Additional technology options that DTEE reviewed include two nuclear technology options. One alternative is to build a new Fermi 3 on the same site as the Company's Fermi 2 with an approximate 1,600 MW gross output. The other nuclear alternative would be to use small modular reactors. The small modular reactors are bundled together at a single site or dispersed at multiple sites. Different types of small modular reactors exist.

Nuclear alternatives are generally large scale and operate best near maximum capacity. Their heat rate of approximately 10,400 Btu/kwH in combination with low cost fuel produces low cost power. Due to challenges to regulatory approval, as well as high initial cost, very few reactors are under construction in the U.S. today. Barriers include the potential for cost overruns, and public concerns about safety and spent fuel disposal. Environmental impacts are low when considering airborne emissions, because there are no carbon or other air emissions, but radioactive waste disposal and uranium mining must be considered. Potential location sites exist within the DTEE territory for nuclear power. Fermi 3 was evaluated in the High Gas Prices scenario within the IRP. That is, it was available to be selected in the High Gas Prices scenario because this scenario is the most favorable for nuclear. In the High Gas Prices scenarios, market prices are high, fuel for gas units is at a disadvantage, and there is a CO_2 price. The nuclear alternative was not selected in the High Gas Prices scenario; therefore, it was not considered any further. The small modular reactors offer flexibility but significant regulatory barriers exist, and this technology is not considered commercial.

Supercritical pulverized coal (PC) and integrated gasification combined cycle (IGCC) units were identified and reviewed as coal alternatives. Supercritical PC aligns with traditional coal-fired generation widely used in the U.S. IGCC is a technology that converts coal to a synthesis gas in a gasifier. The gas produced is then used to fuel a combined cycle power generating plant. Both technologies are in the developmental stages due to the inclusion of CCS. CCS is an unproven technology with very high costs. One plant is currently under construction while the other has recently started operation. The project schedule is assumed to be 60 months for both coal alternatives. The characteristics of each coal alternative are listed in Table 10.2-1.

Table 10.2-1: Generic Coal and Nuclear Characteristics used in IRP Modeling

	Subcritical Pulverized Coal	Integrated Gasification Combined Cycle	Nuclear
Unit Characteristics			
Summer net Cap (MW)	748	629	1560
Summer Net Plant Heat Rate (Btu/kWh)[1]	13,592	10,280	10,400
Tech Rating (developmental, mature, commercial)	Developmental	Developmental	Mature
Project Schedule (months)	60	60	144
Capital Cost ($/kW)[3]	7,132	7,341	6,657
First Yr Fixed O&M ($/MW)[2]	47,551	67,341	90,000
First Yr Variable O&M ($/MWh)[2]	8.52	6.13	0[5]

Table Notes:

1. Heat Rate values expressed in higher heating value (HHV)
2. First-year fixed and variable O&M numbers computed without accounting for Transmission Network Upgrade costs (outside the fence)
3. Capital costs include owner costs, owner contingencies and cost allocation for substation and natural gas site utilities
4. In the evaluation study, the units were dispatched at an annual capacity factor between 80 percent and 90 percent, to determine the O&M estimates.
5. All nuclear O&M is included in the fixed O&M

Carbon capture and storage (CCS) was assumed to be a required technology on new coal units, due to the changing emissions regulations over the last few years, DTEE's announced aspiration of a low carbon future, public perception, and the expected difficulty to obtain environmental permits without low CO_2 technologies. CCS is not yet considered commercially available due to technical challenges and requires very specific siting for storage. Both factors make CCS high risk and high cost. New supercritical PC and IGCC units offer large base load generating capacity, however have higher heat rates, and high costs due to the required CCS. They are also challenged from a regulatory perspective due to water and air effects. Limited locations exist in DTEE's territory for new coal alternatives due to the need for coal deliveries and other interfaces.

10.3 Wind and Solar

10.3.1 WIND

DTEE continues to evaluate future wind options, including whether to self-build, build/transfer from a third-party developer, or contract through a Power Purchase Agreement. Several factors to consider when evaluating future wind parks include technology, geography, and Production Tax Credits (PTCs).

Turbine technology continues to evolve and reduce the pricing for wind generation. Turbine manufacturers are developing larger turbines, and turbine technology is also increasingly better suited for lower wind resources, such as those DTEE sees in most of the state of Michigan. DTEE's most recent wind park is sited using 2.5 MW turbines, and DTEE expects that any future park would have turbines with at least 2.5 MW nameplate capacity.

Regarding geography, 10 of the 14 wind parks that DTEE owns or contracts with are in Michigan's Thumb region. This area of the state has the best wind resource, with current net capacity factors (NCFs) for the parks in the Thumb tracking in the low to mid-forties. However, the area has increased restrictions on zoning and ordinances making future development in this area uncertain. Regions outside of the Thumb have a less robust wind resource; however, turbine technology improvements have increased the opportunity to build competitively priced wind parks in lower wind resource zones.

The federal government has outlined PTC phase-out plans with available PTCs stepping down by 20 percent each year starting in 2017. In other words, wind parks that are initiated, either by start of construction or safe harbor, in 2017 will qualify for 80 percent of PTC value. As this subsidy is phased out, the levelized cost of electricity coming from future wind parks is expected to increase based on the reduced value of the PTCs.

DTEE continues to have land holdings in various parts of the state, and continues to partner with land owners for future wind development. Additionally, the Company regularly meets with developers to learn about future projects.

With the passage of PA 342, which increases the state's renewable portfolio standard to 15 percent by 2021, DTEE anticipates an additional 500 MW–700 MW of renewable energy capacity to meet the new mandate. This will include a mix of wind and solar resources. For planning purposes, DTEE expects a 3-year lead time to develop future wind parks. The Company is using the assumptions in Table 10.3.1-1 for future wind parks.

Table 10.3.1-1: Input Assumptions for Future Wind

Future Wind	2018	2019	2020	2021	2022	2023
Installed Cost ($/kW)	$1,641	$1,533	$1,526	$1,519	$1,416	$1,409
Park Size (MW)	150 – 250					
NCF	30% - 32%					
O&M ($/kW)	$16					
O&M Escalation	2.5%					

10.3.2 SOLAR

Pricing of solar continues to fall, making it increasingly viable in DTEE's renewable energy fleet. While most of DTEE's solar fleet to date is less than 1 MW_{AC}, DTEE's newest and largest solar park is the combined Turrill Rd. and Demille Rd. 48 MW_{AC} arrays in Lapeer. DTEE expects future solar development to focus on arrays greater than 3 MW_{AC} to take advantage of economies of scale. The Company may also consider building smaller projects for demonstration and diversity purposes, but the scale of these projects would not have a significant effect on DTEE's resource portfolio. DTEE's renewable energy development team monitors and evaluates land available for solar projects, and regularly tracks the latest technology. To date, DTEE has primarily installed fixed tilt solar installations, but with each request for proposal, DTEE examines the latest economics for the technology. DTEE is open to considering tracking systems if the economics improve on future installations.

For planning purposes, DTEE expects a 3-year lead time on future solar arrays, driven by an 18-24-month Generator Interconnection Agreement (GIA) application process for new projects in the MISO queue. The Company is using the assumptions in Table 10.3.2-1 for future solar parks.

Table 10.3.2-1 Input Assumptions for Future Solar

Future Solar	2018	2019	2020	2021	2022	2023
Installed Cost ($/kW$_{DC}$)[1]	$1,297-1,470	$1,240-1,430	$1,182-1,380	$1,125-1,340	$1,091-1,300	$1,058-1,260
Park Size (MW$_{AC}$)	3 – 100					
NCF$_{AC}$[2]	19-20%					
O&M ($/kW$_{AC}$)[3]	$12-23					
O&M Escalation[2]	1.9-2.5%					

[1]Source: *Low end-Internal estimate (used in IRP Strategist); High end-U.S. Renewables Deployment Forecast: Solar PV, Distributed Wind, and Biogas to Electricity Capacity and Revenue Forecasts: 2016-2025. Boulder, Colorado: Navigant Consulting. Inc. 2016 (used in LCOE).*

[2]Source: *Low end-Internal estimate (used in IRP Strategist); High end-Internal estimate (used in LCOE).*

[3]Source: *$12-Internal estimate (used in LCOE); $23-HDR alternatives analysis, Exhibit A-38 (used in IRP Strategist).*

10.4 Grid-Scale Energy Storage

Grid-scale energy storage systems (ESS) are a collection of methods used to store electrical energy on a large scale within an electrical power grid. Grid-scale ESS help stabilize the grid by balancing electricity supply and demand over short- (sub-seconds to minutes) to longer-term (hours, days, weeks, etc.) durations. Depending on the ESS technology and configuration, the five applications that ESS can provide value to the grid are:

Generation Application

1. **Ancillary services:** ESS can help maintain the grid's performance by providing ancillary services (e.g., frequency regulation, and/or balancing voltages on the grid). The extent to which the ESS are compensated for these services depends on the market they are operating in.

2. **Capacity:** ESS can be used as a peak shaving resource to reduce or defer investments in additional generation capacity. This includes the use of an ESS as a capacity resource.

3. **Price arbitrage:** ESS can store energy produced during periods of low demand/prices and sell during periods of higher demand/prices. In the same context, ESS can also increase the value of renewable energy systems by storing and shifting renewable energy output to times of greater system need or to avoid curtailment (i.e., firming renewable energy capacity).

Distribution Application

4. **Investment deferral in distribution:** Similarly, ESS can be used as a peak shaving resource on the

distribution system to reduce or defer investments in additional distribution assets.

5. **Emergency backup:** ESS can provide electricity supply during planned or unplanned outage situations

Today, most ESS projects focus on one application. However, depending on the circumstances, the ESS may be less than fully-utilized (e.g., operating only a few hours a year to shave peak power loads). In the future, a single ESS project may be configured to provide two or more applications to allow the ESS to improve its utilization and generate additional value.

As indicated previously, different ESS technologies are more suitable for certain applications than others. Certain technologies are more suited towards storing and discharging bulk power over longer durations (e.g., pumped hydro) while others are better suited to manage shorter duration imbalances in the power system (e.g., flywheels). The DTEE 2017 IRP focused on generation application of the ESS projects. The following ESS technology categories comprise most of ESS technologies commercially available today:

- Solid state batteries (e.g., lithium-ion, sodium-sulfur, and lead acid)
- Flow batteries
- Flywheels
- Compressed air energy storage
- Thermal
- Pumped hydroelectric power

In Table 10.4-1 each technology was evaluated based on the specific value it can provide to the grid. Technologies were ranked according to suitability.

- Suitable (S): the technology has been used for this application at the pilot or commercial level.
- Potentially suitable (PS): the technology has the potential to be used for this specific application, but few or no installations exist.
- Unsuitable (U): the technology is unlikely to be suitable for this specific application.

Table 10.4-1 Energy Storage Systems Installed Cost – Basis for Usage

	Li-ion Battery	Lead Acid Battery	NaS Battery	Flow Battery	Flywheel	Compressed Air (CAES)	Pumped Hydroelectric
Capacity (Resource Adequacy)	S	S	S	S	US	S	S
Arbitrage	S	PS	PS	PS	US	S	S
Ancillary Services	S	S	S	PS	PS	PS	S
Block Size [1] (in MW)	100	20	50	20	20	100	500
Dispatch Duration Hour [2]	4	4	8	2	0.5	varies	varies
Capital Cost [3] ($/kwh)	$600	$500-$1400	$600-$1200	$400-$1000	$900-$3000	$200-$400	$300-$500
Economic Service Life [4]	10	10	10	15	20	20	40+

Table Notes

1. Commercial available scale (proven block size). The output of some systems (advanced lead-acid, CAES, pumped hydroelectric) is geographically limited.
2. Typical durations for current-day technology (manufacturers have ability to vary, at increased cost and risk).
3. 2015 cost basis, with utility finance model used. Range represents many different effects (e.g., scale, site, interconnect, other). Range midpoint cost can be used for IRP calculations as applicable. Cost basis is for technology use as a DTEE "capacity" asset (maximum storage duration/block)
4. Derived from HDR database, augmented by references including those from Energy Storage Association, Lazard, California ISO, and others (assumes standard vendor warranty including annual monitoring/adjustment/replacement); recommended for IRP modeling.
5. Diabatic cycle compressed air stored underground is expanded through CTG compressor and turbine, resulting in a reduced demand for natural gas firing in same unit. Natural gas consumption is nominally 60% of an equivalent-output CCGT without CAES assist. Total energy input, with CAES and gas combustion summed, is actually higher for the CAES assisted cycle.

The lithium-ion battery, at the pilot or commercial level, was shown to satisfy the desired attributes the best, with a large block size of 100 MW and dispatch duration of four hours. Therefore, the lithium-ion battery was chosen as the energy storage system to be modeled in the IRP.

Evaluation of 100 MW lithium-ion battery storage using renewables for charging the batteries was performed. The lithium-ion battery has an average round trip efficiency of 85 percent (over the life of the battery) and offers a cycle life between 2,000 to 3,000 cycles.

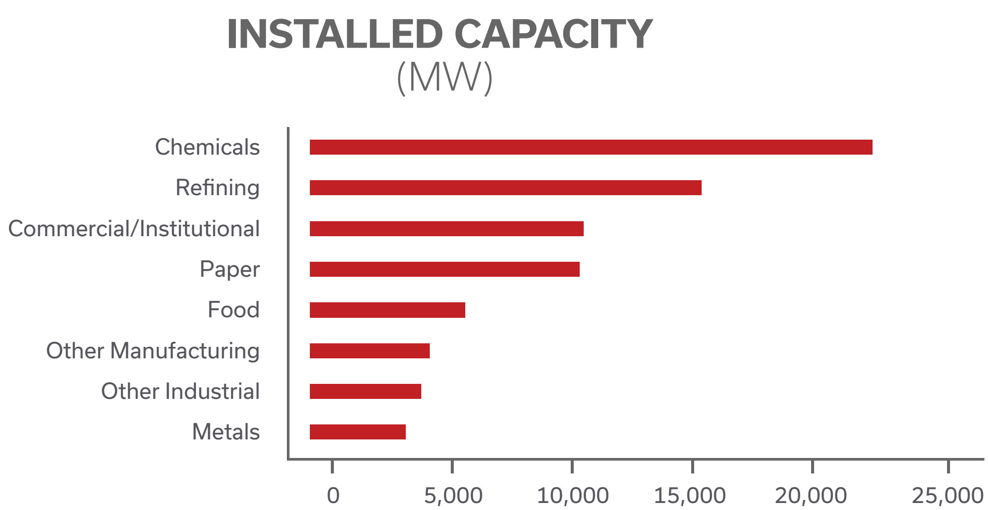
DTEE will continue to evaluate and track battery storage as an option for investments in its generation fleet. As costs decline, performance improves, and the market framework for batteries evolves, the Company's perspective on its economics and range of applications may change.

10.5 Combined Heat and Power

Combined heat and power (CHP) – sometimes referred to as cogeneration – is the concurrent production of electricity and thermal energy from a single source of energy. CHP systems can use a variety of fuels and generating technologies (i.e., steam turbine, reciprocating engine, fuel cells, and gas turbines), and has been utilized for many years, mostly in industrial, large commercial, and institutional applications.

Typically, CHP systems are utilized and sized to meet the coincident power and thermal loads of a single site and/or user. Given this fact, over 85 percent of existing CHP capacity in the U.S. as shown in Figure 10.5-1, is concentrated in large population centers and in industries with high coincident power and thermal loads (e.g., chemicals, refining, paper, and food processing).

Figure 10.5-1: Existing CHP Capacity in the U.S. by Facility Type



Source DOE CHP Installation Database (U.S. installations as of December 31, 2014)

In addition to the need for coincident power and thermal loads, CHP adoption can be influenced by a variety of economic and non-economic factors, including: state-level incentives, spark spreads, energy market structures, environmental and sustainability initiatives and/or policies, and user-specific power infrastructure resiliency requirements. Taking these factors into account, DTEE analyzed the potential for CHP penetration in its service territory over the next five to ten years and expects future CHP capacity additions to be relatively small.

Due to the site-specific nature of CHP, modeling CHP as a utility-owned capacity resource can be difficult. However, certain instances offer opportunities, and CHP projects will continue to be considered on a case-by-case basis as a potential option to fulfill long-term capacity obligations.

10.6 Demand Response

10.6.1 LONG-TERM DEMAND RESPONSE MODELING INPUTS

To determine the potential for demand response programs, DTEE conducted a demand response potential study with GDS Associates, Inc. in 2016 to determine the achievable potential through 2035.

The demand response potential study provides a roadmap for determining the opportunities for cost-effective demand response programs within the DTEE service area. For this study, GDS produced the following estimates of potential: technical potential, economic potential, and achievable potential.

Achievable potential was used in DTEE's IRP modeling.

Technical potential is the theoretical maximum amount of capacity that could be displaced by a demand response program, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the program. It is often estimated as a snapshot in time, assuming immediate implementation of all technologically feasible measures, with additional opportunities assumed as they arise from program activities.

Economic potential refers to the subset of the technical potential that is economically cost-effective as compared to conventional demand-side capacity resources. Both technical and economic potential are theoretical numbers that often assume immediate implementation of measures, with no regard for the gradual ramping-up process of real-life programs. In addition, they ignore market barriers to actual implementation. Finally, they consider only the costs of the measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them.

Achievable potential is the amount of capacity that can realistically be expected to be displaced assuming different market penetration scenarios for cost-effective programs. An aggressive scenario, for example, could provide program participants with payments for the entire incremental cost of any required equipment. This is often referred to as "maximum achievable potential." Achievable potential takes into account real-world barriers to convincing end-users to adopt demand response programs, the non-measure costs of delivering programs (e.g., administration, marketing, tracking systems, monitoring, and evaluation), and the capability of programs and administrators to ramp up program activity over time. Achievable potential savings is a subset of economic potential. Achievable potential in the demand response study includes programs already in existence and should not be interpreted as incremental potential.

Table 10.6.1-1 provides a graphical representation of the relationship of the various definitions of demand response potential.

Table 10.6.1-1: Types of Demand Response Potential

Not Technically Feasible	Technical Potential		
Not Technically Feasible	Not Cost-Effective	Economic Potential	
Not Technically Feasible	Not Cost-Effective	Market & Adoption Barriers	Achievable Potential

As with any assessment of potential, this study necessarily builds on many assumptions and data sources, including the following:

- The life of demand response programs, capacity savings, and program-level costs
- The discount rate for determining the net present value of future savings
- Projected penetration rates for demand response programs
- Projections of DTEE-specific electric avoided costs
- Future changes to current technology for buildings and equipment

The data used for this report was the best available at the time this analysis was developed in December of 2015. As technologies change and as capacity prices fluctuate, additional opportunities for demand response may occur while current practices may become outdated.

All results were developed using customized Residential, Commercial and Industrial sector-level potential assessment analytic models and DTEE-specific cost-effectiveness criteria, including the most recent DTEE-specific avoided cost projections for electricity.

10.6.2 OVERVIEW OF APPROACH

GDS used a bottom-up approach to estimate demand response potential in the Residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings and screening for cost-effectiveness first at the program level, then summing savings at the end-use and service area levels. In the Commercial and Industrial sectors, the GDS team utilized the bottom-up modeling approach to first estimate program-level savings and costs as well as cost-effectiveness, and then applied cost-effective savings to all applicable shares of electric load.

10.6.3 SUMMARY OF RESULTS

The data in Table 10.6.3-1 shows that cost-effective demand response resources could play a significantly expanded role in DTEE's capacity mix over the next 20 years. This table is a summary of the achievable potential as analyzed by GDS Associates. This analysis provided by GDS Associates reflects the total potential of the demand response programs and includes the effects of the existing DR programs operated by DTEE; this is not representative of incremental potential.

Table 10.6.3-1: Summary of Achievable Savings for 2016-2035 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**

10.6.4 LONG-TERM DEMAND RESPONSE MODELING

DTEE is developing and planning cost-effective demand response programs and tariffs to offset future capacity needs. Several demand response programs that DTEE is currently evaluating based on the results of the GDS study include:

Programmable Communicating Thermostat Program with Dynamic Peak Pricing: DTEE participated in the American Reinvestment and Recovery Act as part of the Smart Grid Investment Grant opportunity in 2011–2013 and developed a smart home program called SmartCurrents. As part of this program, customers were enrolled in a Dynamic Peak Pricing rate and provided a programmable communicating thermostat as part of a scientific customer behavior study. In this study, DTEE would send a control signal to the thermostat during critical peak events and raise the set-point by four degrees on the unit. The customers had the ability to override or opt-out of the event by changing the thermostat set point, but in doing so would be subject to the DPP tariff of $1.00 per kWh for the duration of the event. The results of this pilot showed that customers could reduce their peak usage up to 45 percent during peak events when using the thermostat and save up to 15 percent on their bill.

Home Energy Reports with Peak Reduction Component: DTEE has established a pilot program in conjunction with Opower/Oracle to measure the usage changes of residential customers who are provided notifications of peak events. These customers are notified the day before an event and provided tips to reduce their peak usage. No rate is associated with this opt-out program, but customers would see reduced charges on their bill based on consumption reductions.

10.6.5 LONG-TERM DEMAND RESPONSE MODELING ASSUMPTIONS

DTEE's demand response programs in the IRP include an assumption of program costs, load reductions, and customer acceptance. These assumptions are based on DTEE's previous experiences with demand response programs, such as the SmartCurrents program, industry benchmarking data, such as the FERC reports on demand response, and the experience of DTEE's Demand-Side Management group.

These proposed programs look at both residential and commercial options and are given a preliminary cost-effectiveness screen against forward capacity price forecasts. See Figure 10.6.8-1.

10.6.6 DEMAND RESPONSE COST

DTEE used cost quotes obtained through discussions with hardware and software vendors to determine the cost of developing demand response programs.

10.6.7 ESTIMATED USEFUL LIFE

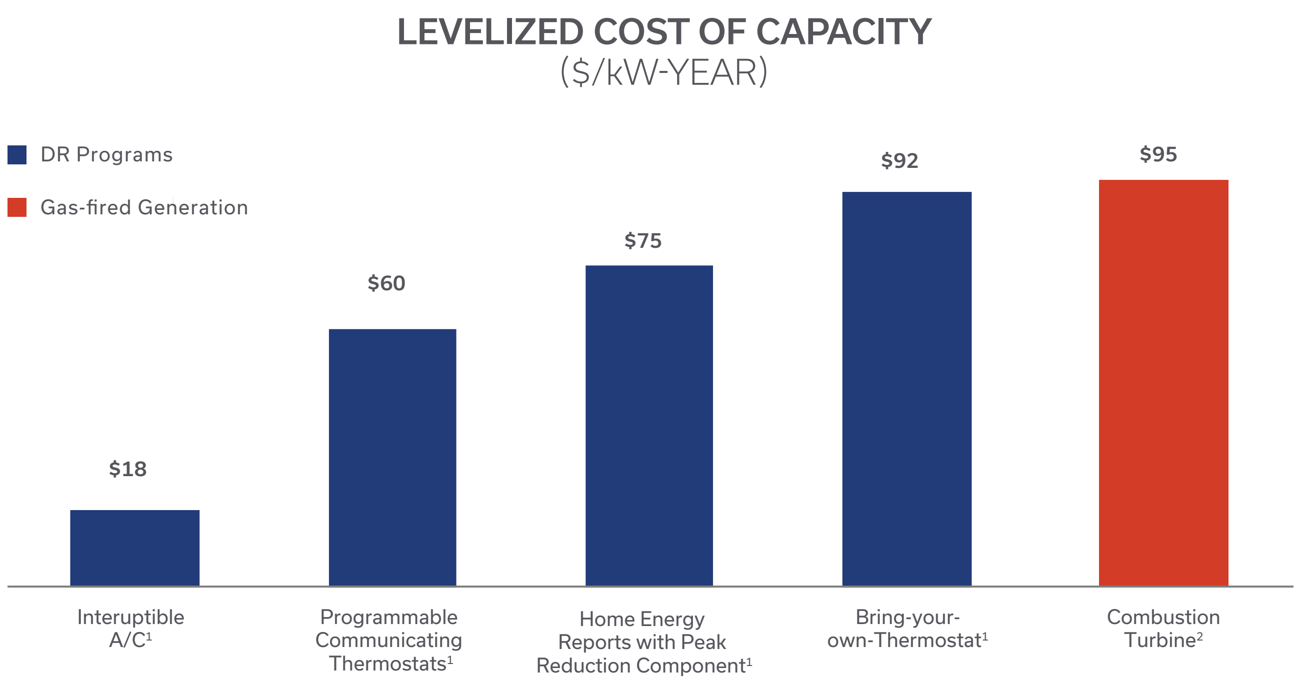
The estimated useful life represents the number of years that demand response programs and equipment are expected to operate. Similar to supply-side resources, demand response resources have a finite life (e.g., hardware becomes obsolete, HVAC systems are upgraded). The useful life estimates for each of the programs were developed based on the Demand-Side Management group's understanding of existing DTEE infrastructure and discussions with hardware manufactures. Depending on the program, the estimated useful life can be from 5 to 20 years.

10.6.8 COST EFFECTIVENESS

Preliminary cost-effectiveness tests were performed to ensure that the demand response programs were viable options. Based on the cost to develop the program and the useful life, calculations were made against the estimated value of the avoided capacity in the MISO market using the Pace Global forecast, as shown in Figure 10.6.8-1.

Program inputs included: capacity savings, coincident peak demand reductions, the number of participants, incremental participant costs, customer incentive costs, program costs, avoided capacity value, and education costs.

Figure 10.6.8-1



The levelized cost of capacity for DR programs compares favorably to the cost of a combustion

1. Internal Analysis of Levelized Program Costs
2. MISO Cost of New Entry (CONE) for planning year 2016/17

10.6.9 DR FUTURE ALTERNATIVES CHALLENGES

Opportunities and challenges lie ahead, and DTEE is well-positioned to continue to provide value to its customers and other stakeholders through a robust and well-run energy demand response portfolio. Options exist for program pilots and expansion through 2021. Other challenges to DTEE include:

- Customer baseline installed efficiency keeps rising as energy efficiency programs and other factors make customers more energy-conscious, reducing loads available for demand response.
- Marketing costs increase when attempting to capture hard-to-reach segments.
- Uncertainty exists regarding design, delivery, and technologies yet to be developed.

As DTEE weighs the effects of plant retirements on Michigan's energy future, demand response can be a low-cost resource for addressing future supply needs as part of a diverse portfolio. Demand response options can come to market faster than building traditional generation and provide customers with options for service with potentially lower rates. While demand-side resources will be an important and expanding part of DTEE's generation portfolio going forward, there is a threshold to their effectiveness. As the demand response resources are used, customers can become fatigued by interruptions and curtailment signals and therefore lower their response. DTEE is addressing this issue by adding programs in a measured approach to ensure the customer response and needed capacity will be there when called. Various scenarios are available for demand response resources to become a viable low-cost resource for compliance, and DTEE will continue to investigate and balance these options in the future, keeping in mind both the customer and the needed generation.

10.7 Energy Efficiency

10.7.1 LONG-TERM ENERGY EFFICIENCY MODELING

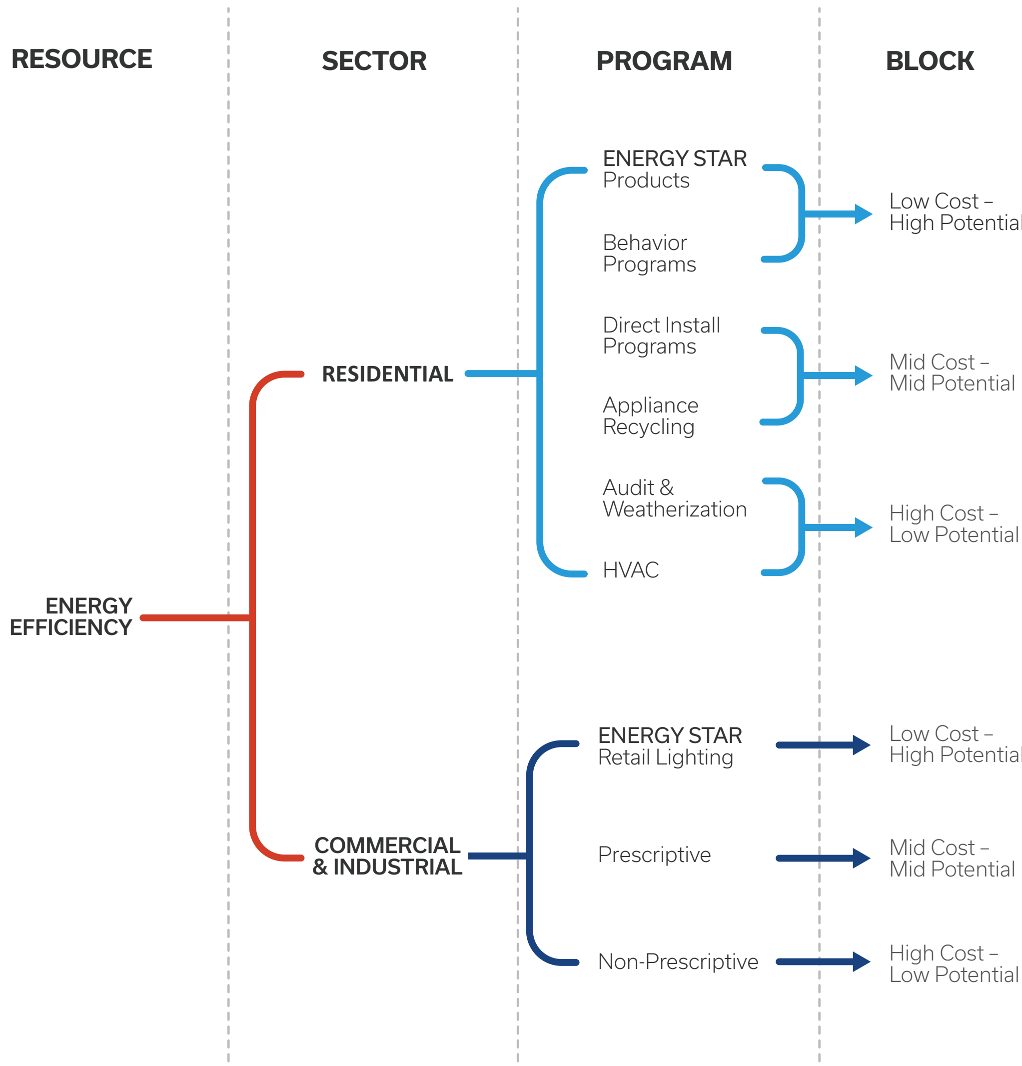
DTEE completed an energy efficiency potential study in 2016 to act as a roadmap for identifying the amount of achievable energy savings potential in its service territory; this study is described in Section 10.7.3. The results of DTEE's energy efficiency potential study have informed modeling assumptions to integrate into its long-term energy efficiency plan. To model its long-term energy efficiency plan, DTEE developed a block approach, which provides flexibility for model selection by being a proxy for energy efficiency programs. The long-term modeling approach is described in detail in Section 10.7.2.

10.7.2 LONG-TERM ENERGY EFFICIENCY MODELING ASSUMPTIONS

DTEE's energy efficiency modeling in the IRP includes an aggregation of its energy efficiency programs into discrete blocks of energy efficiency categories that reflect the characteristics of existing programs but do not require the development of detailed program designs; see Figure 10.7.2-1.

DTEE's energy efficiency programs address the major components of energy consumption in the areas of lighting, appliances, building shell improvements, HVAC/control upgrades, industrial process changes, and behavior. Assumptions on changes to load shapes and reductions in demand and energy can be derived from the results of existing programs and projected for blocks, which serve as proxies of yet-to-be-defined future programs, as well as continuation of existing efforts. This approach provides greater flexibility, reduces the time needed to develop modeling inputs, and affords the opportunity for the model to select an optimum level of energy efficiency on an annual incremental basis to match the given strategy and sensitivity.

Figure 10.7.2-1: Energy Efficiency Modeling Block Hierarchy



*Direct Install Programs: Low-Income, Home Energy Consultations, On-Line Energy Audit, School Program, Multifamily

Blocks were grouped by sector based on the available energy savings potential and program cost. The block sizes provide flexibility for model selection by being a proxy for energy efficiency programs. Each block also has an associated set of modeled data, including the peak demand reduction, operational characteristics, and an 8,760-hour load shape consistent with the sector end-use load shape. Since each block occurs at the end-use level, the characteristics were grossed-up for distribution losses to create a supply-side equivalent when modeled with other resource options.

DTEE defined the amount of energy savings available for each block based on its energy efficiency potential, described in Section 10.7.3. The energy efficiency potential study reported savings by end-use application, whereas DTEE reports savings in its annual EWR reconciliation filing to the MPSC by program. This was reconciled by allocating the achievable energy savings potential to DTEE programs appropriately based on the type of end-use application. DTEE then aggregated the achievable energy savings potential to the appropriate block.

10.7.3 LONG-TERM ENERGY EFFICIENCY MODELING INPUTS

The energy savings associated with each block has limits based on the available achievable potential in DTEE's service territory. These limits are driven by program development, customer awareness, market penetration, participant acquisition and other customer and market factors.

To determine these limits, DTEE conducted an energy efficiency potential study with GDS Associates, Inc. in 2016 to determine the achievable potential through 2035. The steps in which the available potential is diminished is similar to a supply stack and includes blocks with low cost–high potential, mid cost–mid potential, and high cost–low potential. As benefits are exhausted from the lowest cost–highest potential block, it moves down the supply stack to the next lowest cost block. Once a block's potential is saturated, the programs are still included to ensure wide and varied participation, but with additional efficiency opportunities assumed as new savings potential emerge due to aging equipment, measure turnover, housing stock development, and technology evolution.

The energy efficiency potential study provides a roadmap for determining the remaining opportunities for cost-effective electric energy efficiency savings for the DTEE service area. For this study, GDS produced the following estimates of energy efficiency potential: technical potential, economic potential, and achievable potential.

Achievable potential was used in DTEE's long-term modeling.

Technical potential is the theoretical maximum amount of energy use that could be displaced by efficiency, disregarding all non-engineering constraints such as cost-effectiveness and the willingness of end-users to adopt the efficiency measures. It is often estimated as a snapshot in time, assuming immediate implementation of all technologically feasible energy saving measures, with additional efficiency opportunities assumed as they arise from activities such as new construction.

Economic potential refers to the subset of the technical potential that is economically cost-effective as compared to conventional supply-side energy resources. Both technical and economic potential are theoretical numbers that often assume immediate implementation of efficiency measures, with no regard for the gradual ramping-up process of real-life programs. In addition, they ignore market barriers to ensuring actual implementation of efficiency. Finally, they consider only the costs of efficiency measures themselves, ignoring any programmatic costs (e.g., marketing, analysis, administration) that would be necessary to capture them.

Achievable potential is the amount of energy use that efficiency can realistically be expected to displace assuming different market penetration scenarios for cost-effective energy efficiency measures. An aggressive scenario, for example, could provide program participants with payments for the entire incremental cost of more energy efficient equipment. This is often referred to as "maximum achievable potential." Achievable potential takes into account real-world barriers to convincing end-users to adopt cost-effective energy efficiency measures, the non-measure costs of delivering programs (e.g., administration, marketing, tracking systems, monitoring, and evaluation), and the capability of programs and administrators to ramp up program activity over time. Achievable savings potential savings is a subset of economic potential.

Table 10.7.3-1 provides a graphical representation of the relationship of the various definitions of energy efficiency potential.

Table 10.7.3-1: Types of Energy Efficiency Potential

Not Technically Feasible	Technical Potential		
Not Technically Feasible	Not Cost-Effective	Economic Potential	
Not Technically Feasible	Not Cost-Effective	Market & Adoption Barriers	Achievable Potential

As with any assessment of energy efficiency potential, this study necessarily builds on many assumptions and data sources, including the following:

- The life of energy efficiency measures, savings, and costs

- The discount rate for determining the net present value of future savings
- Projected penetration rates for energy efficiency measures
- Projections of DTEE-specific electric avoided costs
- Future changes to current energy efficiency codes and standards for buildings and equipment

The data used for this report was the best available at the time this analysis was completed on April 20, 2016. As building and appliance codes and energy efficiency standards change, and as energy prices fluctuate, additional opportunities for energy efficiency may occur while current practices may become outdated.

All results were developed using customized Residential, Commercial and Industrial sector-level potential assessment analytic models and DTEE-specific cost-effectiveness criteria, including the most recent DTEE-specific avoided cost projections for electricity. To help inform these energy efficiency potential models, up-to-date energy efficiency measure data was primarily obtained from the following recent studies and reports:

- October 2015 Michigan Energy Measures Database (MEMD)
- Energy efficiency baseline studies conducted by DTEE
- 2009 EIA Residential Energy Consumption Survey (RECS)
- 2007 American Housing Survey (AHS)
- 2003 EIA Commercial Building Energy Consumption Survey (CBECS)

These sources provided valuable information regarding the current saturation, costs, savings, and useful lives of electric energy efficiency measures considered in this study.

10.7.4 OVERVIEW OF ENERGY EFFICIENCY POTENTIAL STUDY APPROACH

A bottom-up approach to estimate energy efficiency potential was used in the Residential sector. Bottom-up approaches begin with characterizing the eligible equipment stock, estimating savings, and screening for cost-effectiveness first at the measure level, then summing savings at the end-use and service area levels. In the Commercial and Industrial sectors, a bottom-up modeling approach was utilized to first estimate measure-level savings and costs as well as cost-effectiveness, and then applied cost-effective measure savings to all applicable shares of electric energy load.

10.7.5 SUMMARY OF RESULTS

The data in Table 10.7.5-1 shows that cost-effective electric energy efficiency resources can play a significant role in DTEE's energy resource mix over the next 20 years. For the DTEE service area overall, the achievable potential for electricity savings based on the UCT cost-effectiveness test screening is 18.8 percent of forecast kWh sales from 2016 through 2035.

Table 10.7.5-1: Summary of Technical, Economic and Achievable Electric Energy Savings for 2016-2035

End Use	Technical Potential	Economic Potential (UCT)	Achievable Potential (UCT)
Electric Savings as % of Sales Forecast			
Savings % - Residential	52.3%	49.0%	20.5%
Savings % - Commercial	41.8%	36.0%	18.9%
Savings % - Industrial	29.7%	17.6%	16.3%
Savings % - Total	42.2%	35.6%	18.8%
Electric Potential			
Savings MWh - Residential	8,903,407	8,339,118	3,499,557
Savings MWh - Commercial	9,557,694	8,242,372	4,313,889
Savings MWh - Industrial	3,871,520	2,286,275	2,118,727
Savings MWh - Total	22,332,621	18,867,765	9,932,173

10.7.6 ENERGY EFFICIENCY COST

Once the savings characteristics for each block was developed, pricing tiers were identified for each block. DTEE used historical energy efficiency cost data to model future cost increases. The baseline costs were priced to align with DTEE's 2018-2019 energy efficiency plan and then escalated using historical cost increases for future years. For the long-term modeling, a 3.98 percent escalation rate was assumed, which is the actual CAGR DTEE has experienced since the inception of its energy efficiency programs in 2009 through 2016. Costs include incentives, implementation, administration and infrastructure, pilot programs, education programs, and EM&V.

10.7.7 ESTIMATED USEFUL LIFE

The estimated useful life represents the number of years that energy efficiency equipment is expected to operate. Similar to supply-side resources, energy efficiency resources have a finite life (e.g., light bulbs burn out, lighting systems must be upgraded, and HVAC equipment must be replaced). The useful life estimates for each of the blocks were developed based on the weighted average of DTEE's 2018-2019 energy efficiency plan and measure lifespan assumptions used by industry standards. The estimated average useful life included in the long-term modeling was 15 years.

10.7.8 COST EFFECTIVENESS

Cost-effectiveness tests were performed to ensure that the overall goal of reducing costs in a cost-effective manner for the utility and its customers is being achieved. DTEE uses the UCT to measure the effectiveness of its energy efficiency program. The DSMore cost analysis tool was used to calculate the UCT benefit-cost ratio.

Two major groups of inputs DSMore uses are the utility input assumptions and the program inputs. Utility input assumptions contain information that is specific to the utility and includes items such as load shape, the commodity and non-commodity cost of energy, customer energy rates, line losses, weather, and discount rates. The utility input assumptions used in the long-term modeling are similar as those that are used in developing DTEE's 2018-2019 energy efficiency plan.

Program inputs include: energy savings, coincident peak demand reductions, incremental participant costs, customer incentive costs, program costs, education costs, and pilot costs. As indicated previously, the UCT was calculated at the block levels and included Low Income programs, Residential programs, and C&I programs.

Assumptions on changes to load shapes and reductions in demand and energy were derived from the DSMore results of the blocks. Energy efficiency programs affect the system to reduce costs through demand reduction as well as energy savings. Energy efficiency provides load matching to DTEE's overall load requirements. This is due to the energy efficiency portfolio design having the same system load shape drivers as the system load. Looking across a typical year, energy efficiency provides fuel and operating cost savings by lowering demand across all months of the year and offsetting the need for base load and intermediate resources.

10.7.9 ENERGY EFFICIENCY SENSITIVITIES

Energy efficiency options were thoroughly evaluated consistent with the assumptions and input contained in the long-term plan. In total, four sensitivities were evaluated ranging from less than 1.00 percent to 2.00 percent of total annual retail sales with various sensitivities. As detailed in Figure 10.7.9-1, sensitivities with energy savings greater than 1.00 percent capture the entire energy efficiency potential by 2030. For example, the 1.00 percent, 1.50 percent, and 2.00 percent sensitivities all provide nearly equivalent total energy savings through 2030, though the energy savings potential is diminished at different rates.

Figure 10.7.9-1: Total Achievable Electric Energy Efficiency Potential (MWh)

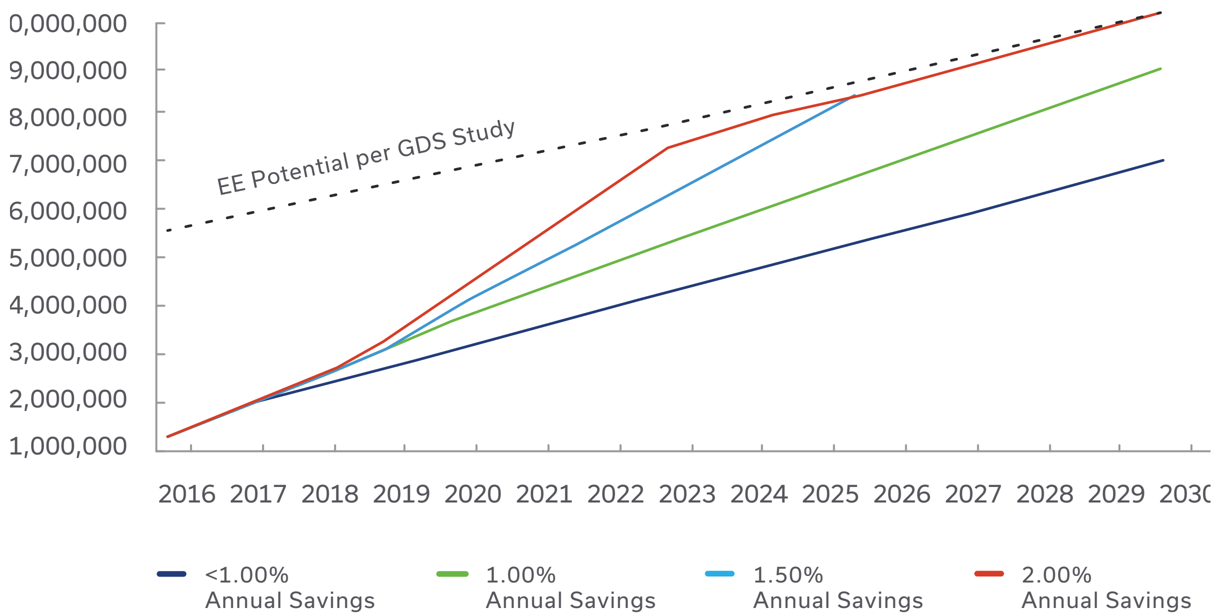


Table 10.7.9-1 details the first-year energy savings for the energy efficiency sensitivities.

Table 10.7.9-1: Sensitivities First-year Energy Savings: MWh

Year	<1.00% Savings	1.00% Savings	1.50% Savings	2.00% Savings
2016	554,835	554,835	554,835	554,835
2017	548,830	548,830	548,830	548,830
2018	557,176	557,176	706,536	965,787
2019	563,954	563,954	702,666	978,190
2020	568,529	568,529	702,547	987,427
2021	479,547	490,640	700,016	992,797
2022	416,687	490,474	737,939	996,798
2023	432,282	490,438	738,798	503,500
2024	440,372	490,625	739,945	279,591
2025	362,864	491,019	612,357	292,819
2026	284,456	491,439	490,690	292,819
2027	303,373	492,245	451,730	306,047

Year	<1.00% Savings	1.00% Savings	1.50% Savings	2.00% Savings
2028	318,148	492,281	332,453	319,904
2029	334,782	492,149	334,419	334,419
2030	342,725	492,005	349,626	349,626

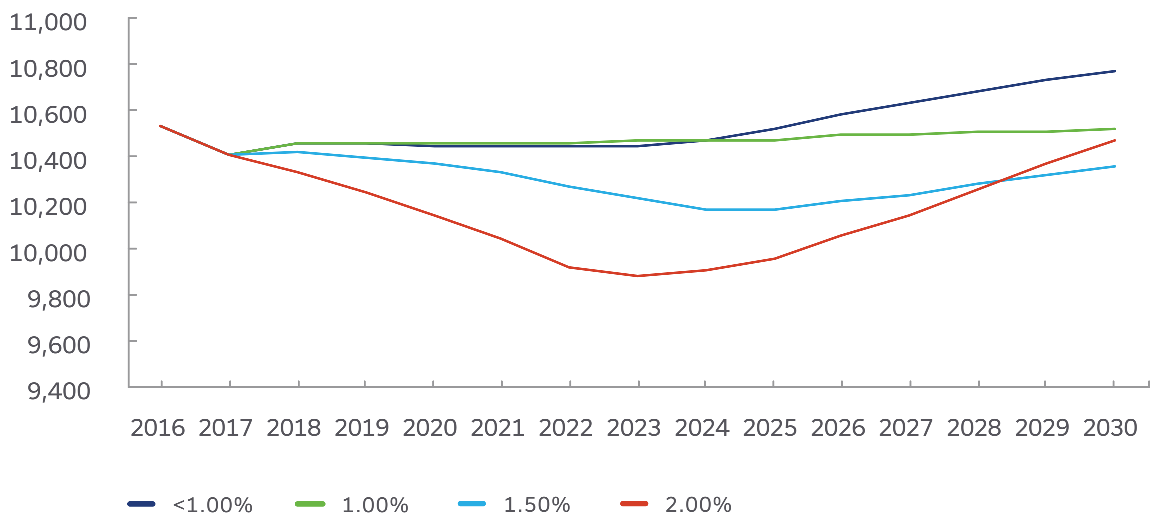
Table 10.7.9-2 details the first-year annual spend for the energy efficiency sensitivities.

Table 10.7.9-2: Sensitivities First-year Energy Spend: $MM

Year	<1.00% Savings	1.00% Savings	1.50% Savings	2.00% Savings
2016	$88	$88	$88	$88
2017	$92	$92	$92	$92
2018	$107	$107	$102	$160
2019	$110	$110	$103	$166
2020	$114	$114	$104	$172
2021	$117	$117	$105	$177
2022	$126	$126	$126	$184
2023	$132	$132	$132	$97
2024	$136	$136	$136	$54
2025	$140	$140	$140	$58
2026	$146	$146	$146	$61
2027	$155	$155	$155	$66
2028	$159	$159	$83	$71
2029	$163	$163	$77	$77
2030	$168	$168	$84	$84

Assumptions on changes to load shapes and reductions in demand and energy were derived from DSMore. A key DSMore output is an 8,760-hourly profile of a "before" end-use shape and an "after" efficient end-use shape that is subtracted to get the net demand reduction. The effect of the projected energy efficiency savings on DTEE's demand forecasts for each sensitivity is displayed in Figure 10.7.9-2.

Figure 10.7.9-2: Coincident Peak with Energy Efficiency Reduction (MW)



A UCT score was calculated based on cost and energy savings for each sensitivity. The basic structure of the UCT involves a calculation of the total benefits and the total costs to determine whether the overall benefits exceed the costs. A UCT is considered cost-effective when the benefit-to-cost ratio is greater than one, and not cost-effective when it is less than one. Results are reported in net present value dollars. Utility input assumptions, described in Section 10.7.8, remained consistent within the DSMore cost analysis tool across all sensitivities. Table 10.7.9-3 details the UCT cost benefits results for each case.

Table 10.7.9-3: UCT Benefit-cost Ratio Results

	<1.00% Savings	1.00% Savings	1.50% Savings	2.00% Savings
Overall UCT Results	5.63	6.32	8.13	7.95

The sensitivity with the greatest benefit-cost ratio is the 1.50 percent case with a UCT score of 8.13. DTEE has included the 1.50 percent sensitivity in the DTEE 2017 IRP.

Although the 2.00 percent sensitivity provides energy savings at a greater rate through 2022, it does so without regard to maintaining a consistent spend and energy savings. Since DTEE may only maintain 2.00 percent energy savings through 2022, customer rates would be inconsistent due to program spending ramping up and down, resulting in unnecessary fluctuations. In addition, the 2.00 percent sensitivity creates the most inconsistency at an administrative level. It would be administratively burdensome to ramp programs up for a short time period and then ramp back down. This fluctuation in programs may result in poor trade ally, vendor, and customer satisfaction.

The DTEE 2017 IRP was developed using the 1.50 percent sensitivity since it is the sensitivity with the greatest demand reduction while being administratively achievable within a budget that is consistent, and this sensitivity achieves the highest UCT score.

10.7.10 LONG-TERM ENERGY EFFICIENCY PLAN

DTEE is planning for an energy efficiency program that delivers annual electric energy savings of 1.5 percent through 2024. After 2024, DTEE expects energy savings to decline due to the convergence of the actual energy savings and the available energy savings potential in its service territory. As detailed in Figure 10.7.10-1, DTEE captures the entire pool of energy efficiency potential by 2026. Afterwards, DTEE achieves energy savings at a rate equal to the energy savings as new potential is created through factors such as equipment breakage and people moving.

Figure 10.7.10-1: Total Achievable Electric Energy Efficiency Potential (MWh)

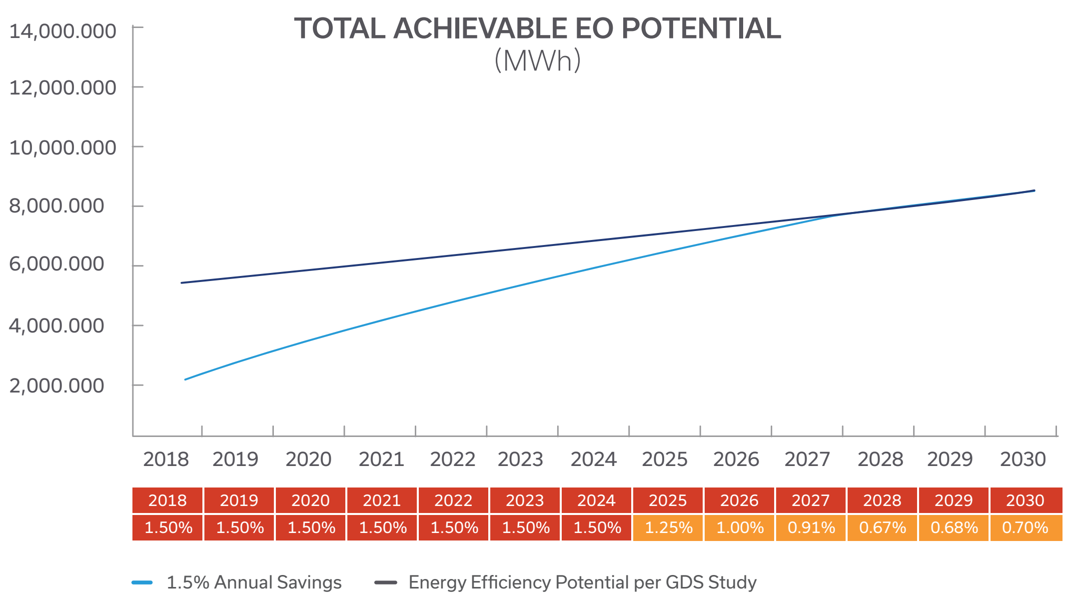


Table 10.7.10-1 details the first-year energy savings and annual spend for DTEE's energy efficiency programs. The total cumulative energy savings from 2022 through 2030 is an estimated 4,788 MWh. The total cumulative investment from 2022 through 2030 is an estimated $1.1 billion.

Table 10.7.10-1: Long-Term First-year Energy Savings, Capacity Savings and Spend (2022-2030)

Year	Planned Energy Savings (MWh)	Planned Capacity Savings (MW)	Spend ($MM)
2022	737,939	127	$126
2023	738,798	125	$132
2024	739,945	125	$136
2025	612,357	97	$140
2026	490,690	75	$146
2027	451,730	74	$155
2028	332,453	57	$83
2029	334,419	56	$77
2030	349,626	59	$84

Table 10.7.10-1 demonstrates that DTEE's planned energy efficiency spend through 2030 may remain consistent with previous spend levels. DTEE believes this level of energy efficiency spend is reasonable and prudent. DSMore results indicate DTEE's long-term energy efficiency plan achieves a UCT benefit-cost ratio of approximately 8.13.

Based on DTEE's experience implementing energy efficiency programs since 2009 and the results of its energy efficiency potential study, DTEE believes the assumptions included in the long-term energy efficiency plan are likely to deliver the projected net energy savings at the identified costs.

10.7.11 ENERGY EFFICIENCY PROGRAM CHALLENGES

DTEE is well-positioned to continue to provide value to its customers and other stakeholders through a robust and well-run energy efficiency program. DTEE has a solid plan through 2019 filed with the MPSC outlining its energy efficiency savings and spend targets for years 2017 through 2019. Savings levels beyond 2024 may become more challenging as the energy savings potential is diminished. In addition, DTEE may face other challenges such as:

- Depletion of low-cost high potential programs
- Diminishing lighting potential as a result of the Energy Independence and Security Act (EISA) and the success of market penetration for LEDs
- Rising customer baseline installed efficiency as energy efficiency programs and other factors make customers more energy-conscious
- Increases in marketing costs when attempting to capture hard-to-reach segments
- Uncertainty around design delivery and technologies not yet developed

The results of DTEE's energy efficiency potential study have informed modeling assumptions to help address these challenges.

10.7.12 SUMMARY

As DTEE weighs the effects of plant retirements on Michigan's energy future, energy efficiency will play an important part of a diverse and flexible set of energy resources in DTEE's portfolio that is consistent with the Company's low carbon aspirations. With a DTEE-specific potential study showing potential savings of 18.8 percent for 2016 through 2035, energy efficiency remains a viable demand-side resource. DTEE evaluated numerous sensitivities to determine the optimal level of energy efficiency savings to provide its ratepayers. Sensitivities were modeled so that drivers such program cost, useful life, cost-effectiveness, coincident peak reduction, energy savings potential, and administration efforts were evaluated to provide robustness in the DTEE 2017 IRP. DTEE's long-term energy efficiency modeling accounts for future uncertainties through its block approach, which will be updated over time as programs are developed.

10.8 Distributed Generation

Distributed energy resources (DER) could potentially delay infrastructure upgrades driven by capacity needs. For distributed energy resources to be considered as non-wire alternatives, it is essential that the distributed resources have the appropriate control equipment to isolate or curtail their power flow and that DTEE is able to verify the operation. Additionally, it is crucial that DTEE has a contractual or rate agreement to ensure that customer generation or demand response through islanded microgrid will operate when called upon in a capacity shortfall or abnormal system condition.

DTEE is actively benchmarking with other utilities and participating in various industry consortiums to learn the best practices for all forms of DER integration. DTEE is also reviewing substation and equipment design so that new substations will be able to accommodate DER integration in the future. One of the most important initiatives that will help the Company better accommodate increasing DER participation in the future is the implementation of Advanced Distribution Management System (ADMS), which is addressed in detail in Section 10.9. The proposed ADMS project will have a distributed energy resource management module specifically designed to manage distributed energy resources.

10.8.1 DISTRIBUTED FOSSIL GENERATION

DTEE has investigated the cost effectiveness of distributed generation in the past. DTEE originally proposed a Distributed Customer Generation (DCG) pilot program in its General Rate Case No. U-17767 filed in December of 2014. Under the proposed DCG pilot program, the Company would provide the needed switchgear and interconnection equipment to the customer at the Company's expense in exchange for the ability to register the customer's generators as resources in the MISO market and contribute to the capacity needed to meet MISO standards. The December 2015 Order in Case No. U-17767 approved the capital requested to cover the cost of the switchgear and interconnection equipment associated with the proposed pilot program. In Case No. U-18014 filed in February of 2016, the Company requested authorization for additional capital expenditures to further the pilot and attract more customer interest. This pilot program would have allowed the Company to develop customer-owned back-up generation as a capacity resource in accordance with the EPA's Reciprocating Internal Combustion Engine (RICE) National Emission Standard for Hazardous Air Pollutants (NESHAP) rules. However, in the spring of 2016, the U.S. Court of Appeals for the District of Columbia ruled in favor of the Delaware Department of Natural Resources and lowered the ability of generators to run without emissions controls and changed the RICE-NESHAP rules. The run hours were reduced from 100 hours to 15 hours, which would not meet the minimum requirements to be a qualified resource. Thus, the Company was unable to justify the investment in the proposed program as the economics to add in the needed emission control equipment was not cost effective. The requested additional capital allocation was ultimately disallowed by the Michigan Public Service Commission in its January 31, 2017 Order in Case No. U-18014. DTEE will continue to work with customers that have distributed generation to explore all options for use in the future. The type of DCG program outlined was not considered a viable resource alternative to be modeled within the IRP.

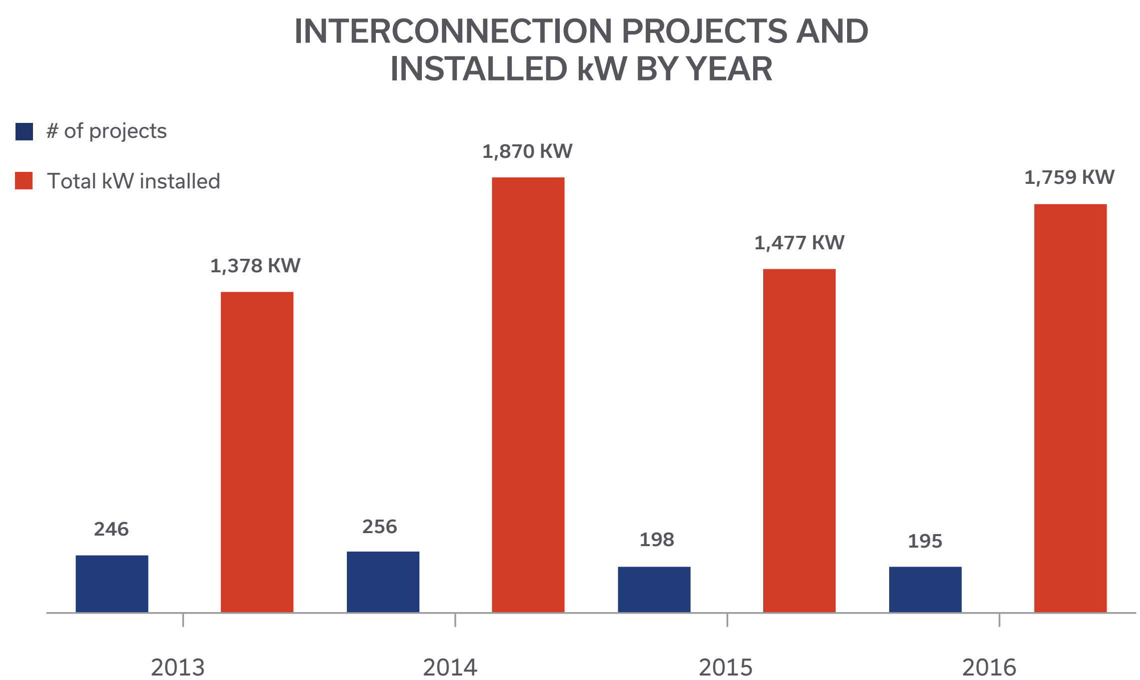
10.8.2 DISTRIBUTED RENEWABLE GENERATION

DTEE accommodates all customers with DG who wish to connect to the electrical grid through the interconnection process. After a study is completed, the required equipment to control and protect the system and other DTEE customers must be installed and tested before a Parallel Operating Agreement (POA) is executed to allow two-way power flow. In the case of small interconnections, this requires a disconnect switch or IEEE-certified equipment. Larger generators may require grid updates and protection schemes such as Transfer Trip. Currently, over 31 large solar parks are connected to the DTEE's electric grid for a total of 66 MW that can power more than 14,000 homes.

The volume of requests for customer-owned DER in the DTEE service area is predominately residential rooftop solar. The typical project size is 5-10 KW for residential customers and 150-750 KW for commercial customers. Additionally, several multi-MW synchronous generators and dynamometers connected to the grid are typically located at commercial and industrial facilities. DTEE has rates for customers that wish to operate their generation parallel to the grid and act as grid resources that can be monitored and controlled by DTEE.

Interconnection applications have ranged from 1,300 kW to 1,900 kW installation each year in the last few years as shown in Figure 10.8.2-1., showing little to no growth. DTEE recognizes that if DG grew at a faster pace, distribution infrastructure would potentially need additional capital investments to meet the needs of DG interconnection, especially with regards to switching and protection. However, at this point, DTEE does not see sufficient evidence of demand increase to confidently project the location or the timing of DG interconnection that would justify infrastructure upgrades.

Figure 10.8.2-1 Historical Trend on Small DG Projects and Installed kW



10.9 Volt/VAR (VVO) Optimization

Volt/VAR optimization technologies balance line voltage and system reactive power to reduce system line losses, reduce peak demand, and improve the efficiency of the distribution grid. VVO also can help manage power quality issues associated with high penetration of intermittent energy resources such as wind and solar.

The benefits of Volt/VAR are highly dependent on the circuit in which it is implemented. Line capacitors, line regulators, and substation load tap changers are installed or upgraded to enable the ability to adjust voltage and reactive power in real time or automatically. Some major influences to the benefits of the Volt/VAR optimization are substation loading, customer load mix, and voltage concerns/violations on circuits.

To achieve Volt/VAR optimization, an integrated system such as an advanced distribution management system is necessary to enable any real-time Volt/VAR optimization. Capacitors and regulators need to be upgraded with the advanced control technology to enable automatic or remote operation. Most capacitors and regulators currently installed in the DTEE system are no longer manufactured or supported by the vendor. New controls were identified to allow these devices to be controlled by the ADMS and report equipment health and monitoring. ADMS installation will allow greater use of Volt VAR optimization. Currently DTEE has only a handful of remotely controllable regulators and capacitors on the distribution circuits.

DTEE has looked at a few pilot programs in the past on Volt/VAR optimization: one pilot in 2013, and a second pilot in 2014. Based on the learnings from the past pilots, another pilot study to upgrade regulators and capacitors with advanced remote control capability is planned for 2018. Based on the results of the 2018 pilot, DTEE will evaluate the benefit/cost of a system-wide capacity and regulator upgrade to enable Volt/VAR Optimization and include the findings in future IRPs.

10.10 Summary

DTEE considered a multitude of resource options to be evaluated for the IRP modeling. A complete list of the resource options and the various levels of analysis is displayed in Table 10.10-1.

Table 10.10-1 Resource Options evaluated in the IRP process

Category	Alternatives Evaluated	Technical Screening	LCOE	Strategist
Simple Cycle	1X0 NGSC (7E.03)	X	X	X
Simple Cycle	1X0 NGSC (LMS100)	X		X

Category	Alternatives Evaluated	Technical Screening	LCOE	Strategist
Simple Cycle	1x0 NGSC (LM6000)	X	X	X
Simple Cycle	3x0 NGSC (18V50SG)	X	X	
Simple Cycle	1x0 NGSC (7F.05)	X	X	X
Simple Cycle	4x0 NGSC (7F.05)	X	X	X
Combined Cycle	3x1 NGCC (7HA.02)	X	X	X
Combined Cycle	2x1 NGCC (7HA.02)	X	X	X
Combined Cycle	2x1 NGCC (7F.05)	X	X	X
Combined Cycle	1x1 NGCC (7HA.02)	X	X	X
Combined Cycle	1x1 NGCC (7F.05)	X		X
Nuclear	Nuclear	X	X	X
Nuclear	Small Modular Reactor	X		
Energy Efficiency	<1.00%	X		X
Energy Efficiency	1.00%	X		X
Energy Efficiency	1.50%	X		X
Energy Efficiency	2.00%	X		X

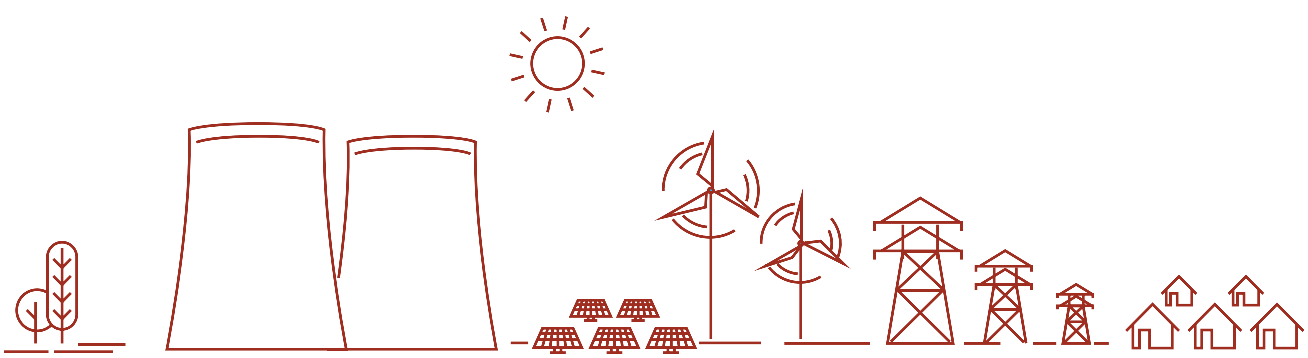
Category	Alternatives Evaluated	Technical Screening	LCOE	Strategist
Demand Response	Behavioral DR	X		X
Demand Response	Thermostat	X		X
Demand Response	Bring your own Thermostat	X		X
Demand Response	Tariff Based DR	X		
Coal	Integrated Gasification with CCS	X	X	
Coal	Supercritical PC with CCS	X	X	
Coal	Retain Existing	X		
Coat to gas Conversion	Existing Coal to Gas	X		
Wind	Wind Offshore	X		
Wind	Wind Onshore	X	X	X
Solar	Solar Conventional PV	X	X	X
Solar	Concentrated solar power (CSP)	X		
Hydro Electric	Hydro Electric	X		
Fuel Cells	Fuel Cells	X		
Waste to energy	Waste to Energy	X		

Category	Alternatives Evaluated	Technical Screening	LCOE	Strategist
Biomass	Biomass Combustion	X	X	
Biogas	Landfill Gas to Energy	X		
Biogas	Digestion to Energy	X		
Biogas	Biomass Gasification	X		
Energy Storage	Lithium-Ion	X	X	X
Energy Storage	Sodium-Sulfur	X		
Energy Storage	Lead Acid	X		
Energy Storage	Flow batteries	X		
Energy Storage	Flywheels	X		
Energy Storage	Compressed air	X		
Energy Storage	Electric Vehicles	X		
Energy Storage	Thermal	X		
Energy Storage	Pumped hydro-electric	X		
Grid-Connected Energy Storage	Hydroelectric/ Compressed Air/Lithium Ion	X		
Distribution	Transmission Import Alternatives	X		

Category	Alternatives Evaluated	Technical Screening	LCOE	Strategist
Distribution - Peak Demand and Consumption	Advanced Metering Infrastructure	X		
Distribution - Peak Demand and Consumption	Time-of-Use Rates and Similar Pricing Structures	X		
Distribution - Peak Demand and Consumption	Direct Load Control	X		
Distribution System Reliability	Feeder Switching	X		
Distribution System Reliability	Monitoring	X		
Distribution - Energy Efficiency and Automation	Voltage Optimization	X		
Distribution - Energy Efficiency and Automation	Conservation Voltage Reduction	X		
Distribution - Energy Efficiency and Automation	Line Loss Reduction	X		
Distribution - Energy Efficiency and Automation	SCADA/Remote Operations	X		
Distributed Generation	Simple Grid-Tied to Auxiliary Bus	X		
Distributed Generation	Microgrid	X		
Distributed Generation	Customer-owned backup Generators	X		
Distributed Generation	Solar Photovoltaic	X		
Distributed Generation	Combined Heat and Power	X		
Geothermal	Geothermal Energy Production	X		

SECTION 11

INTEGRATED RESOURCE PLAN MODELING



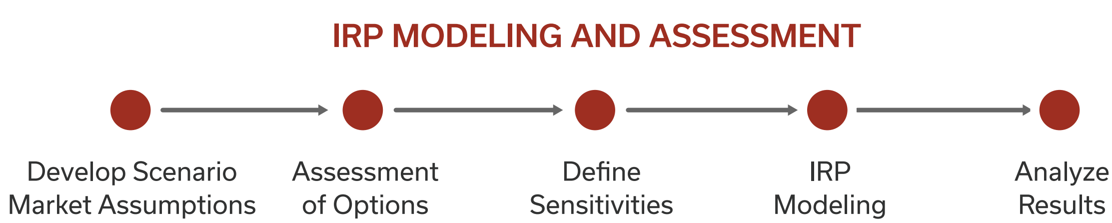
11 Integrated Resource Plan Modeling

An effective IRP process delivers an optimal resource portfolio based on a thorough review of industry and cost driver assumptions of supply-side and demand-side options, along with future uncertainties. After a need was identified, DTEE performed a screening process using a technical assessment, levelized cost of electricity analysis and market valuation to distill down the number of alternative technologies considered. Then DTEE modeled several scenarios and sensitivities and considered the DTEE Planning Principles to identify a long-term resource plan that would perform well under diverse future conditions. This section details the modeling process, including market assumptions, assessment of alternatives, sensitivities, IRP modeling, and the results.

11.1 Overview of IRP Modeling and Assessment

To develop a long-term resource plan DTEE performed a robust modeling assessment to identify the types and combinations of flexible resources that DTEE could use to meet the future power needs of its customers. The modeling and assessment process is shown in Figure 11.1-1 and explained in further detail in this section.

Figure 11.1-1: IRP Modeling and Assessment Process



Develop Scenario Market Assumptions

DTEE's process tested several options around resource alternatives under different sets of uncertain future conditions called scenarios. The set of resource alternatives selected in any one future scenario defines how DTEE might provide power to its customers under those conditions.

Assessment of Options

Part of the process was to identify the types and combinations of flexible resources that DTEE could use to meet the future power needs of its customers. DTEE's process tested several options under three screening methodologies. First, DTEE utilized HDR, Inc., an external consultant, to technically screen out options based on its engineering evaluation study. The next methodology was to screen the many alternatives against the market scenarios with an economic analysis using a levelized cost of electricity (LCOE) evaluation, as is discussed in Section 11.3.1. The technologies that passed the LCOE screening were then run using the third methodology, a market valuation, which is presented in Section 11.3.2.

Define Sensitivities

Sensitivities are modeling assumption variables that change but are unique to the DTEE service territory. Under each scenario, DTEE tested a set of resource options, also referred to as resource plans, with sensitivities to understand the effect of varied assumptions.

A base resource plan, or a set of resource option assumptions which are consistent under each scenario, was utilized to test against the resource plans derived from the sensitivities.

IRP Modeling

DTEE relied upon the Strategist module PROVIEW to evaluate the various combinations of available demand-side and supply-side alternatives to meet DTEE's future resource requirements. Data from the supply-side and demand-side alternatives was input directly into PROVIEW to evaluate each of the alternatives head-to-head. The total set of resource alternatives considered for the demand-side and supply-side integration consisted of the short-list candidates that remained after the initial LCOE and market valuation screenings.

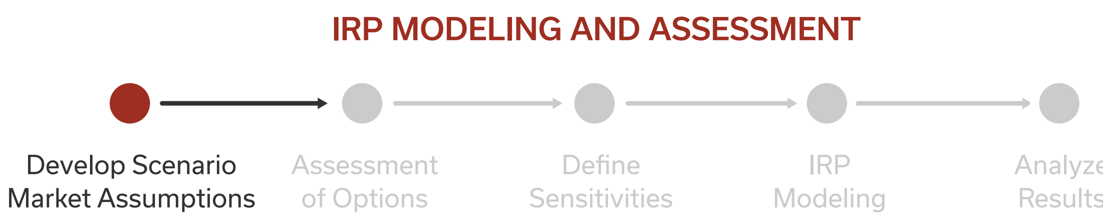
The alternatives were evaluated with attention to the resource start date for the availability of the resource to meet DTEE's demonstrated resource requirements. Resource plans were exposed to scenario and sensitivity analyses to test the robustness of those plans. PROMOD and an internal revenue requirement model were utilized to further analyze resource plans.

Analyze Results

Results of the IRP modeling were analyzed using an Integration analysis. Integration analysis is the process in which the electric demand forecast is satisfied with existing owned-generation, demand-side and supply-side alternatives, including renewable and distributed generation. The integration process results in a ranking of various resource plans, or combination of resource plans, based on the optimization of constraints. An economic ranking of options is determined to enable the selection of flexible and reliable resource alternatives can be made. From scenario and sensitivity modeling and evaluating the resource plans with the DTEE Planning Principles, DTEE determined a 2017 Integrated Resource Plan that would be further analyzed with the risk assessment described in Section 12.

11.2 Develop Market Scenario Assumptions

Figure 11.2-1: IRP Modeling and Assessment Process – Develop Scenario Market Assumptions



The scenarios, shown in figure 11.2-1, refer to broad national market assumptions and help to understand the future, which is uncertain and can be difficult to predict. Scenarios encompass the entire U.S. and consider how federal laws, technology cost curves, commodity supply and demand, and economic build/retirements of generating units' interplay to create long-term market projections. When making important business decisions or large investments, it is best practice to consider how those decisions may play out under a variety of different "futures." DTEE seeks to identify a resource plan that performs well under a broad array of future conditions (e.g., higher fuel prices or lower CO_2 emissions). This will ensure that the resulting long-term resource plan will provide optimal solutions to DTEE's future demands for electricity.

DTEE hired the consultant Pace Global to perform detailed national modeling utilizing the AURORAxmp® software. Pace, in conjunction with SMEs from many different areas of DTEE, including Environmental, Fuel Supply, Renewables, and Corporate Energy Forecasting, agreed on the scenarios to be modeled.

Once the underlying assumptions were finalized, the actual national modeling took place. The results were then vetted collaboratively with Pace Global and DTEE. After the vetting process was complete, the market outputs generated by the national modeling were used as inputs into the detailed DTEE IRP modeling. The market assumptions incorporated in the IRP modeling are referred to as fuel, energy, capacity, and emission prices. Descriptions of the various scenarios follow.

Reference: This scenario assumed that abundant low-cost supplies keep natural gas prices low. This has multiple effects: electricity market prices remain relatively low, and there are significant coal retirements due to favorable economics and pressure from continued environmental regulation of new gas units over older coal units. Due to the large number of coal retirements and new natural gas builds, the nation can comply with the CPP or similar constraints, without the need for significant carbon prices or renewable builds beyond current state mandates.

High Gas Prices: Higher natural gas marginal production costs result from higher demand, increased exports, increased costs applied to fracking operations by an increase in gas industry regulations, or a combination of the three. This leads to fewer new gas plants built and fewer coal plant retirements. The higher levels of coal plants remaining have the effect of increased CO_2 emissions, leading to higher carbon prices, which in turn incent more renewables and natural gas to meet CPP goals or similar constraints.

Low Gas Prices: Low cost natural gas supplies and continued productivity improvements keep gas prices low. This drives more coal and even some nuclear retirements due to lower power prices and reduced coal plant dispatch. CO_2 emissions plateau at a lower level, thereby eliminating the need for any carbon prices to drive down CO_2 emissions, assuming the CPP or similar constraints.

Emerging Technology: Decreasing costs and higher efficiencies for renewables (especially solar) and storage across the country leads to higher renewable penetration and lower CO_2 emissions, which would comply with the CPP or similar constraints. CO_2 prices are zero in this scenario. Electricity market prices are also lower in this scenario due to the abundance of zero dispatch cost renewable technologies.

Aggressive CO_2: This scenario assumed that the carbon regulations or agreements will be tightened post-2030 to keep the U.S. on a trajectory to meet 80 percent reduction by 2050, which is in alignment with the Paris Accord. This scenario assumed that new sources are included under the CO_2 emissions cap, which differs from the CPP assumed in some other scenarios. After 2030, emissions continue to decline as coal is phased out in favor of renewables and gas technologies.

Table 11.2-1 displays the scenarios used for the IRP modeling.

Table 11.2-1 DTE Electric Scenario Descriptions

Scenarios →	Reference	High Gas Price	Low Gas Price	Emerging Technology	Aggressive CO_2
Storyline	Majority of States comply with Final CPP on a mass basis, creating a robust, liquid allowance market. Low gas prices and weak load growth continue	Due to higher natural gas supply curves and external demand from LNG exports and other sources, gas prices are higher than the reference	Same as Reference, however continued downward pressure on gas prices persists throughout the study period	Same as Reference, with Optimistic view on cost / performance curves on wind, solar, and battery technologies	The CO_2 target is tightened starting in 2030 and continues on roughly the same pace as the CPP average reduction but drawn to achieve 80% reduction by 2050
CO_2 assumption	Mass-based, coal units curtailed, no CO_2 price needed	Same as Reference: CO_2 price ($2-$31 rise) from 2022 to 2040	Same as Reference, no CO_2 price needed	Same as Reference, no CO_2 price needed	Mass-Based on a smaller pool of allowances drives higher prices ($2-$40) from 2026 to 2040
Gas Prices **($/mmbtu nominal)**	Henry Hub @ $3.00 near term and rising to $4.50 in 2025 and ~$6.00 by 2035	Henry Hub rising to $6.28 in 2025 and $8.40 in 2035	Henry Hub @ $2.75 near term rising to ~$5.00 by 2035	Henry Hub @ $2.70 near term rising to ~$5.50 by 2035	Same as Reference case
Renewables	Install renewables economically (nationally and Michigan), using current mandates as minimums	Incremental additions due to economics / CPP compliance	Additional builds require incentives due to competition from gas technology	Higher levels of renewables across US projected (25-40% by 2030, 50%+ by 2040)	Higher levels of renewables projected

The IRP modeling was very extensive and took a significant amount of time to prepare, run, and analyze the models. Because the process was started a year before filing the IRP, it is inevitable that some inputs have changed in that amount of time. To fully address the effect of the changes to assumptions from 2016 to 2017, a sixth scenario was produced in 2017 with the most up-to-date forecasts. The 2017 refreshed scenario will be denoted as "2017 Reference" scenario; the others will have no year associated with their name. While the earlier scenarios had slightly different inputs, the range of sensitivities ensured that the 2016 scenarios are still valid, and fall within the range of assumptions that were used in the 2017 Reference scenario. All discussion on the 2017 Reference scenario is in Section 12 Risk Analysis. In this section, scenarios and assumptions will focus on the five IRP scenarios completed in 2016. All the scenarios except for the Aggressive CO_2 scenario assumed compliance with the Clean Power Plan (CPP) as written.

The following sub-sections detail the results of the fundamental modeling outputs obtained through the national modeling.

11.2.1 NATURAL GAS

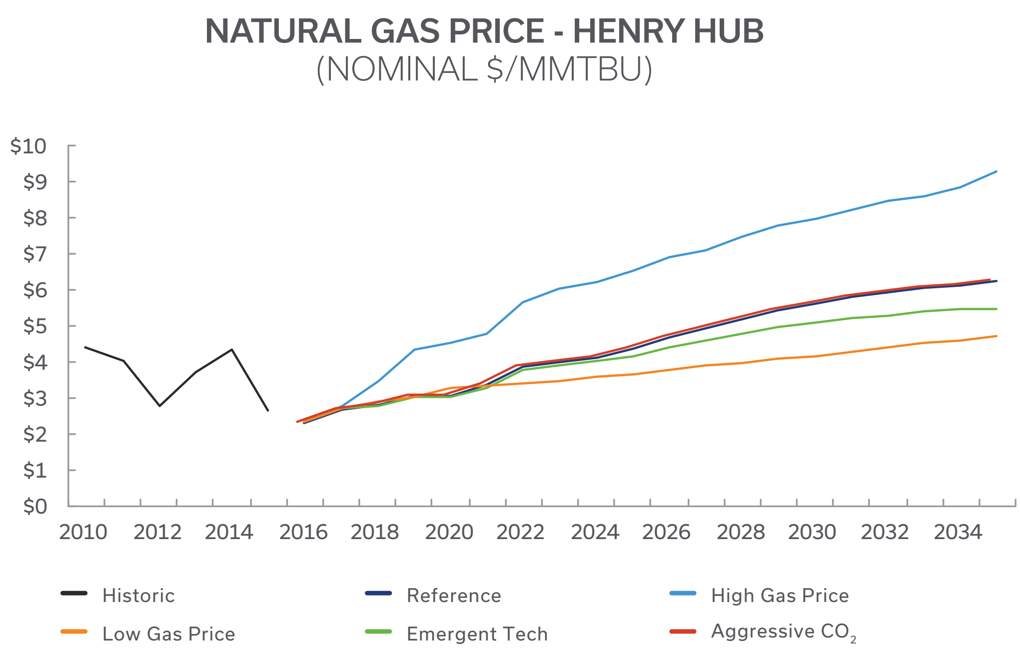
The price of natural gas is a key output of the national market scenarios. The High Gas Prices scenario assumed that increased natural gas exports and other demand push companies to higher cost natural gas production areas.

The Emerging Technology scenario has the same underlying supply and demand assumptions as the Reference scenario, but increased renewables cut into demand and reduced the gas prices.

The Reference scenario and the Aggressive CO_2 scenario have the same gas prices.

The prices at Henry Hub are shown in Figure 11.2.1-1. There are also adders that need to be applied to bring the gas to Michigan and to the power plant. The adders are based on historical price differences between Henry Hub and Michigan, as well as the expected costs to transport that gas to the power plant burner tip.

Figure 11.2.1-1



After the forecast of natural gas price at Henry Hub was determined, the natural gas supply, transportation, and storage costs were estimated for a combined cycle generator. In order to provide a reliable supply of natural gas to the power plant, firm gas supply and firm transportation services were considered.

Gas supply costs were based on natural gas pricing for the Company's Belle River peakers. The forecasted price of gas for this site is based upon the Henry Hub price (as shown in Figure 11.2.1-1) plus an adder based upon an index for the Dawn, Ontario hub, which is one of the most liquidly traded hubs in the region. In addition, the adder includes the cost associated with a lateral pipeline connecting the gas generator to transmission pipelines.

Gas transportation costs were based on transportation capacity that covers the maximum fuel consumption of the generators.

The storage service was needed to balance the ratable flows of the gas supply with the non-ratable consumption of the generator by injecting gas when the supply exceeds consumption, withdrawing gas when the consumption exceeds supply, and storing this gas as needed. The annual cost of the firm gas transportation and storage services were estimated at $30.5 million. This combination of firm gas supply, firm transportation, and firm storage would provide a high level of fuel supply reliability to the plant.

11.2.2 ELECTRICITY MARKET PRICE PROJECTIONS

MISO zone 7 power prices forecasts are shown in Figures 11.2.2-1 and 11.2.2-2. On-peak refers to 7 a.m. to 11 p.m. EST Monday through Friday. The hours of 11 p.m. through 7 a.m. EST Monday through Friday, as well as all weekend hours, constitute the off-peak. Monthly data was obtained. Appendix F contains details of the methodology for translating the forecasted prices to the hourly price streams that DTEE used in the PROMOD and Strategist models.

Figure 11.2.2-1

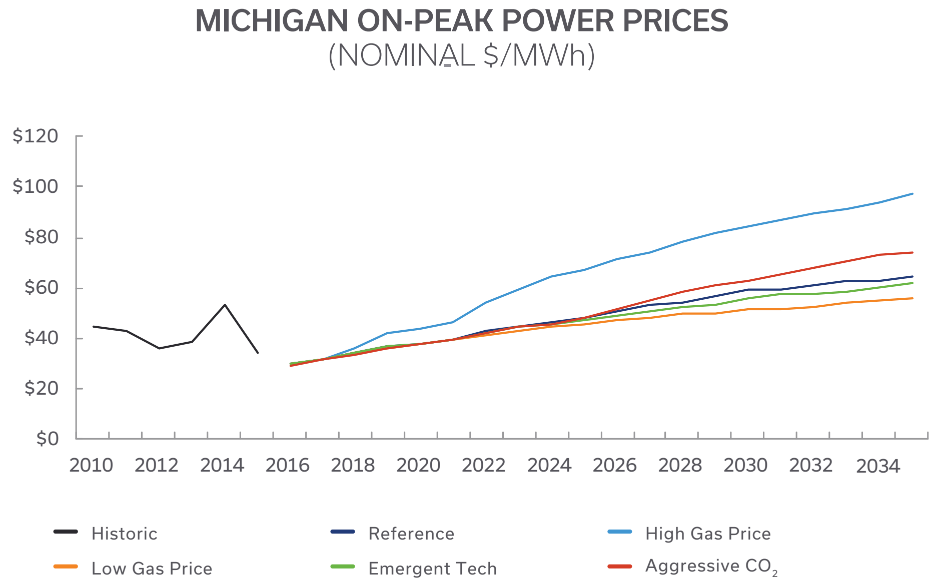
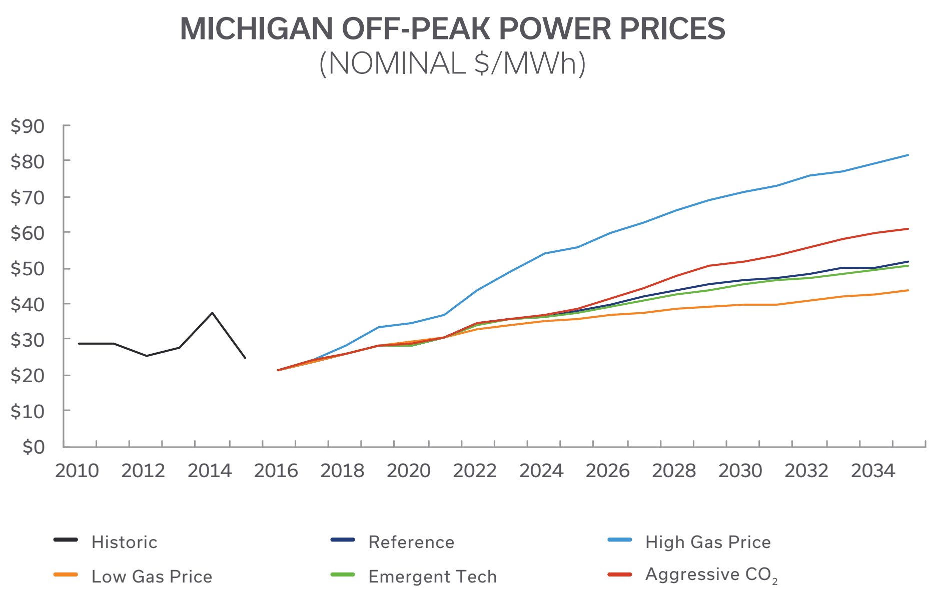


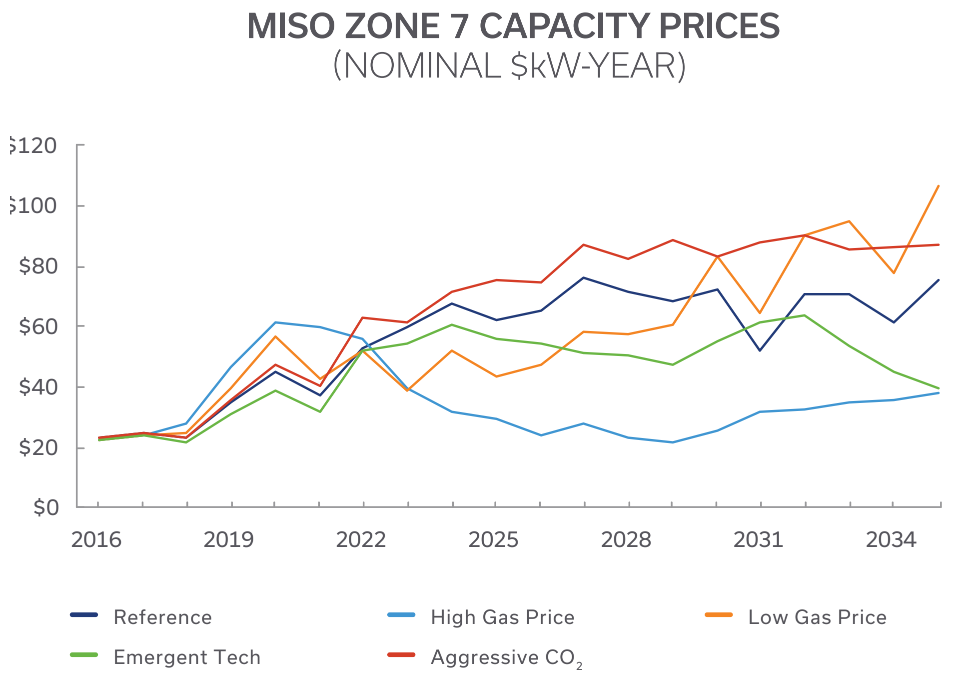
Figure 11.2.2-2



11.2.3 CAPACITY PRICE FORECAST

Capacity prices refer to the cost of obtaining capacity to meet the reserve requirement by year. These values were determined as part of the national modeling process. Capacity prices were determined for each relevant independent system operator (ISO) and zone, calculated as a function of the Net Cost of New Entry (Net CONE) and forecasted reserve margins in the relevant zone. CONE or Full CONE in this calculation is the fixed costs of a new combined cycle (Capital and Fixed O&M). Net CONE means that the Full CONE price has been offset by the energy margins. For more details on the calculation of capacity prices, see Appendix G.

Figure 11.2.3-1

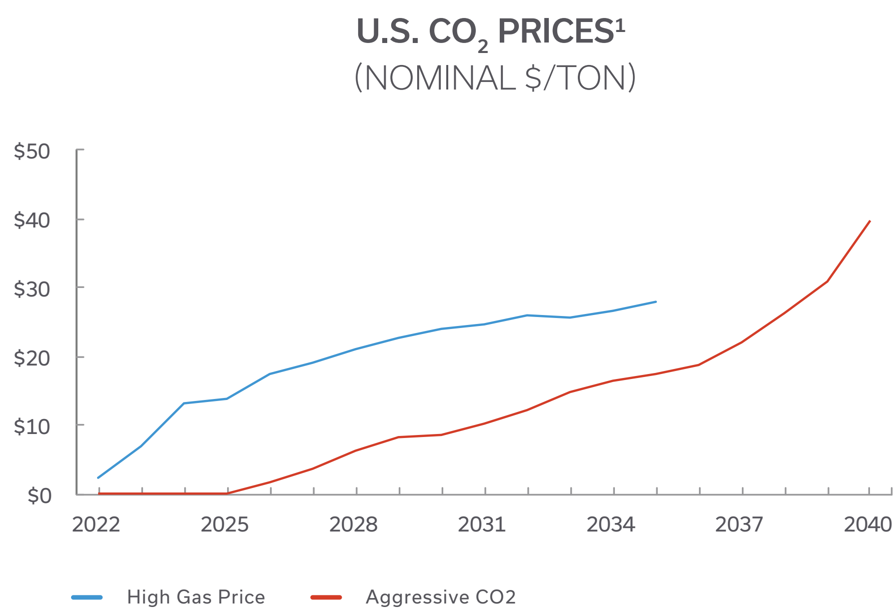


Since DTEE is part of MISO zone 7, only that zone is shown. The capacity price stream for the High Gas Prices scenario shown in Figure 11.2.3-1 is the lowest because the methodology to calculate capacity prices is based on Net CONE and the energy revenues or margins are highest in this scenario. A different phenomenon is occurring with the Emerging Technology scenario, in which renewables and storage capacity are abundant. This increases reserve margins in zone 7 and drives capacity prices down in the out years.

11.2.4 EMISSIONS PRICES

CO_2 prices were determined in the modeling by a multi-step process for each scenario. First, constraints for national CO_2 emissions were established, based on the Clean Power Plan. The national models were run with the other assumptions for the scenario and the CO_2 emissions were checked. If they were above the constraint, then a shadow price was added to the unit dispatch in the model. This makes the high CO_2 producing units run less, and the low CO_2 producing units run more, driving down the CO_2 emissions. Once the shadow prices result in national CO_2 emissions within the constraint, they are converted to CO_2 market prices, as shown in Figure 11.2.4-1. In the Reference, Low Gas Prices, and Emerging Technology scenarios, the modeling determined that the constraints for CO_2 established in the modeling were met without imposing a penalty; therefore, the CO_2 prices are zero throughout the study period.

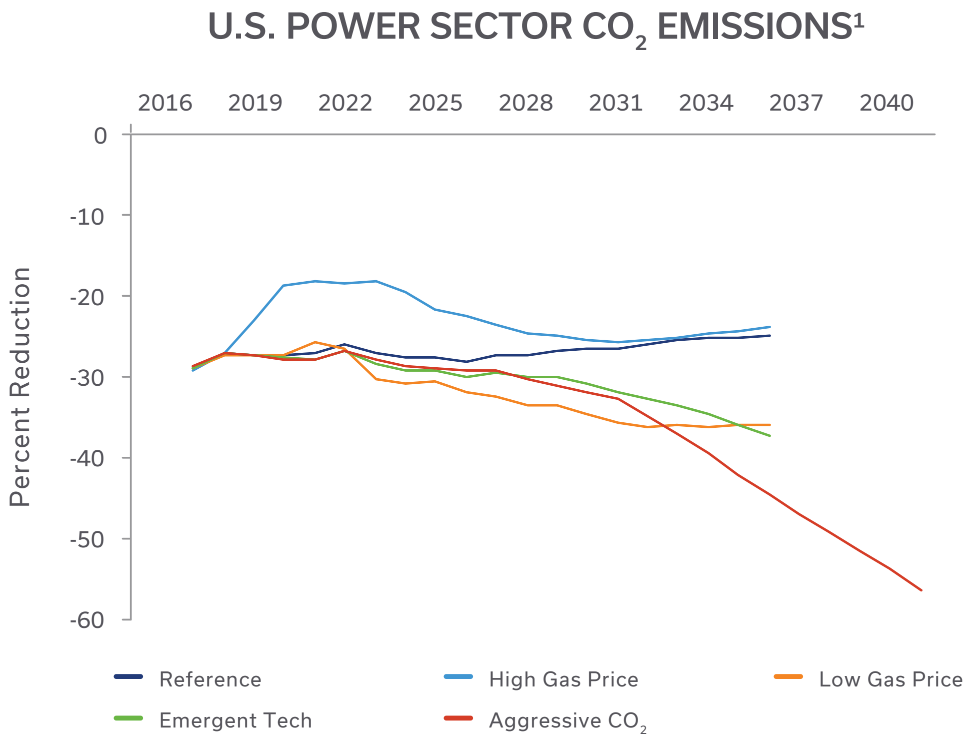
Figure 11.2.4-1



[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.

The CO_2 trading encompassed the U.S. states except for California and the Northeast Regional Greenhouse Gas Initiative (RGGI) states. It was assumed that these states remain on their own established CO_2 trading platform. The rest of the U.S. trades at the prices shown and remains below the established CO_2 emissions constraint. U.S. Power sector emissions forecasts are shown in 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.

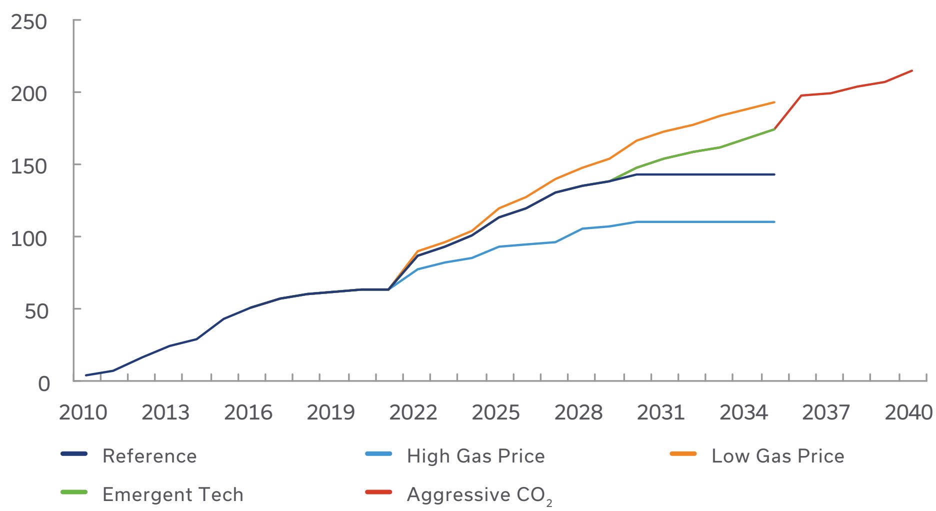
NO_X and SO_2 prices were established to meet the constraints imposed by the Cross-State Air Pollution Rule (CSAPR). These prices are the same in all scenarios, assuming no real change in SO_2 and NO_X policy across the scenarios. Changes to emissions policies across scenarios were assumed to be in CO_2 prices. For details on the NO_X and SO_2 prices, see Appendix H.

11.2.5 OTHER MARKET DRIVERS

Coal plant retirements assumed in the national modeling varied among the five scenarios, as shown in Figure 11.2.5-1.

Figure 11.2.5-1

CUMULATIVE U.S. COAL RETIREMENTS[1]
(GWs)



[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.

In the national modeling, plants were assumed to retire based on their economics. In the Reference scenario, for example, 144 of the total 322 GW of coal capacity will either retire or convert to gas by 2030. In the High Gas Prices scenario, coal plant retirements are lower because the market prices are higher, making coal more competitive with new natural gas units, despite the expensive capital projects required to keep operating. In the Emerging Technology scenario, the coal units are competing with new renewables along with the lower gas prices. In the Aggressive CO_2 scenario, coal retirements are relatively steady, reaching the highest point in 2040, when 66 percent of coal is retired.

The new additions to replace the retiring coal units and to account for new growth are shown in Figures 11.2.5-2 and 11.2.5-3.

Figure 11.2.5-2

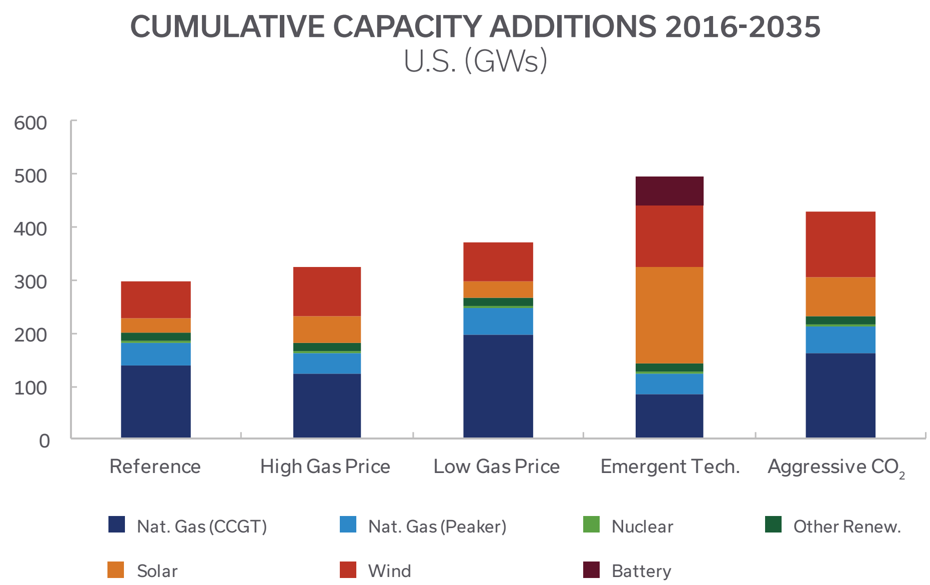
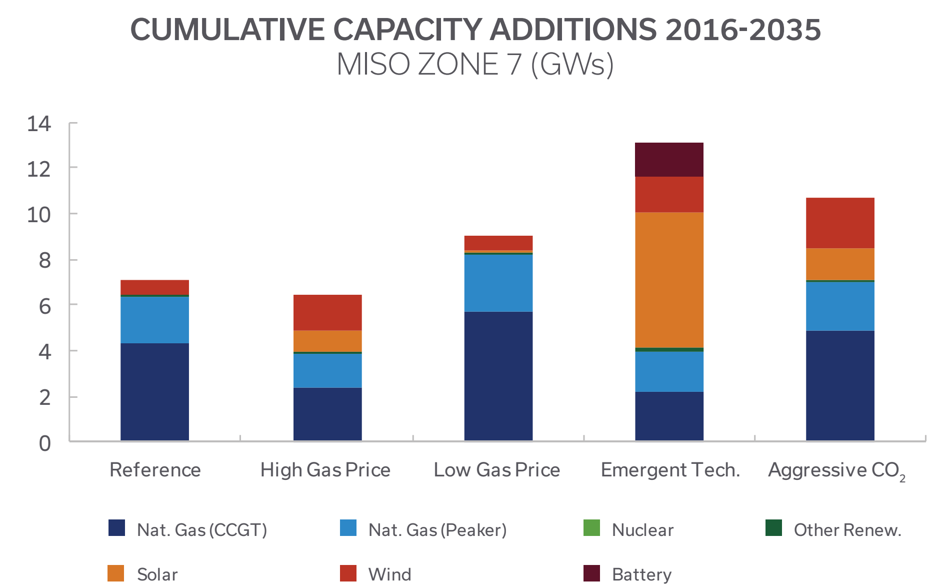


Figure 11.2.5-3

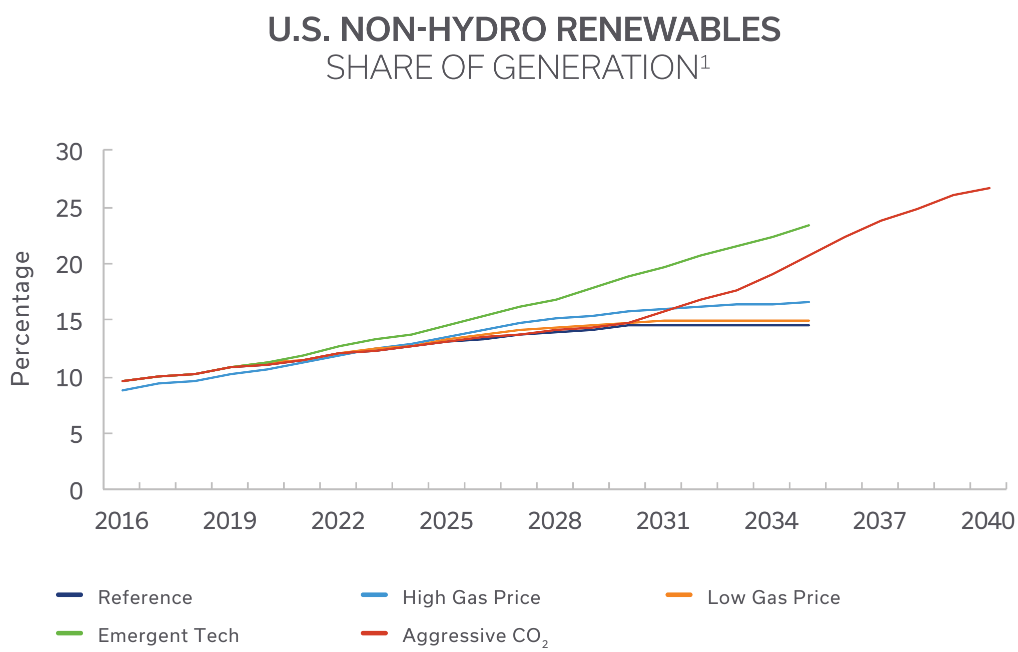


In the Emerging Technology scenario, the solar build is quite large due to the lower cost assumptions, as is battery technology deployment.

Renewable Penetration

The level of renewable build as shown in Figure 11.2.5-4, is higher in cases in which the gas prices rise, cost assumptions fall, or CO_2 emission caps tighten. In the High Gas Prices scenario, this occurs because keeping coal online in combination with renewables build is enough to keep below the CO_2 constraints instead of building new gas units. In the Emerging Technology scenario, the technology costs decrease to the point at which renewables and battery technology are economical. In the Aggressive CO_2 scenario, CO_2 prices make coal and gas less economical compared to renewables.

Figure 11.2.5-4



[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.

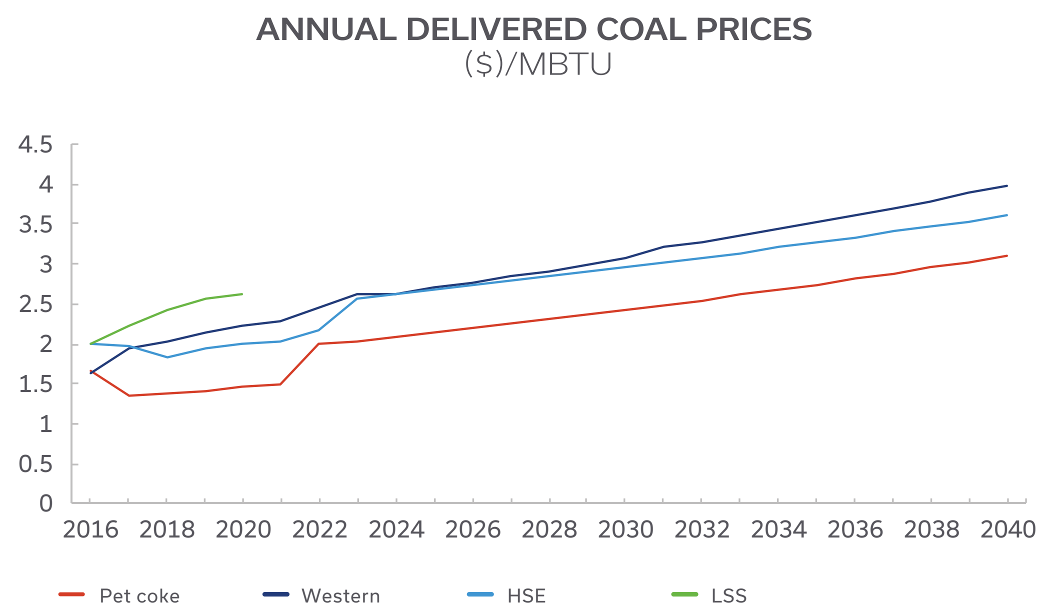
11.2.6 BLENDING OF FORWARDS AND FUNDAMENTALS

Up to this point, this section has covered the results of the national fundamental scenario modeling. These results make up most of the market inputs into the DTEE Strategist and PROMOD models. However, market forecasts developed through fundamental models do not align exactly with what is happening in markets today. To account for this, DTEE employed a blending methodology to ensure alignment between the market forward pricing seen currently and forecasts derived from fundamental modeling.

11.2.7 COAL PRICES

The eastern and western coal prices used in the IRP modeling were determined utilizing coal forwards pricing data from the Company's Fuel Supply group and the Pace Global forecast specific to Michigan delivery. The Pace Global forecast supplies delivered prices from central and northern Appalachian and the Powder River Basin coal mines. For DTEE purposes, Appalachian coal prices represent the Eastern fuel and Powder River Basin coal prices represent the western fuel. Market forwards were also utilized for Monroe petroleum coke from 2016 to 2021. The forwards forecast ends in 2021 then transitions in 2022 to the Pace Global forecast starting in 2023. This accounts for the step change seen in 2022 in Figure 11.2.7-1. For more details on coal prices, see Appendix I.

Figure 11.2.7-1: Annual Delivered Coal Price Forecast



River Rouge also utilizes blast furnace gas (BFG) and coke oven gas (COG). A ratio of 0.77 for BFG and 0.80 for COG was applied to the River Rouge western coal price to determine the fuel cost for these gases.

11.2.8 FORECASTED OIL PRICE

To determine the forecasted oil price, DTEE utilized the NYMEX forwards for oil prices from 2016 to 2021 and the Pace Global forecast for 2022 to 2040 as shown in Figure 11.2.8-1. These prices were provided in dollars per barrel and then converted to dollars per MBtu using the conversion factors shown in Table 11.2.8-1.

Figure 11.2.8-1

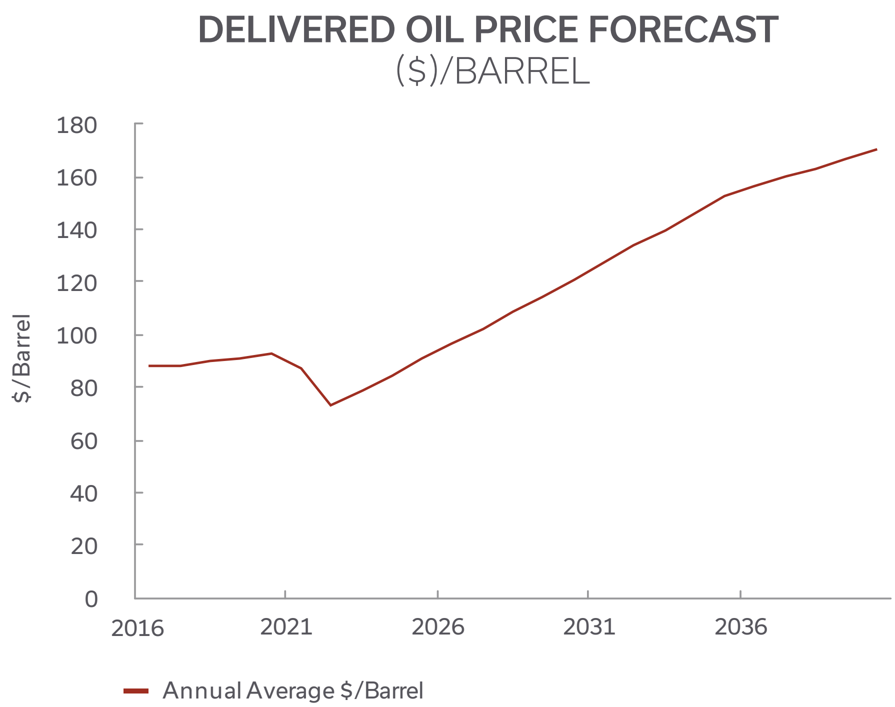


Table 11.2.8-1: Btu Content Per Gallon Based on Oil Type

Oil Type	Btu/gal
#2 Oil (USLD)	138,000
#6 Oil	145,000

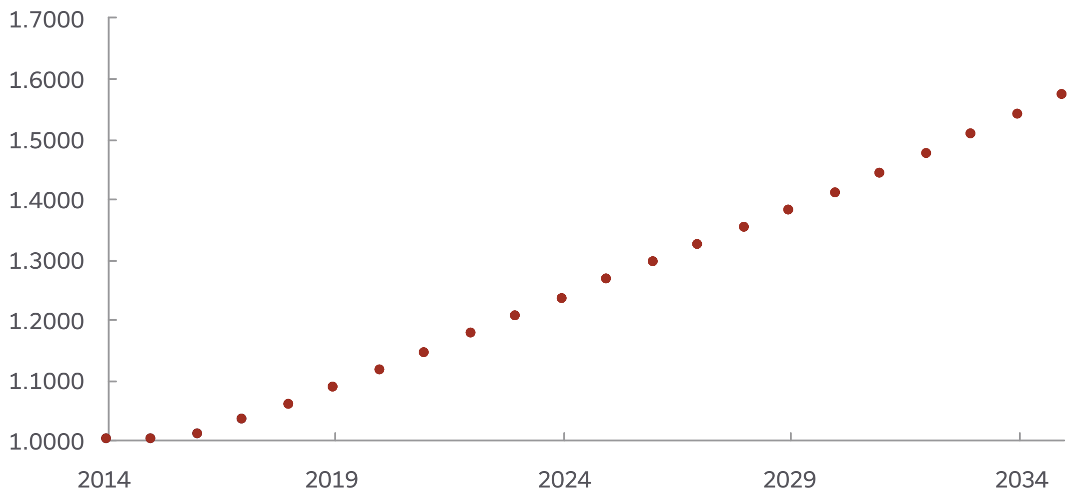
For the price details on oil, see Appendix J.

11.2.9 ESCALATION RATE

The modeling used the deflator series shown in Figure 11.2.9-1, based on the Unadjusted Consumer Price Index (CPI-U). This escalation rate was used throughout the scenario development and in the alternatives development, and is tied to the sales forecast developed by the Load Forecasting group. Fuel prices have their own escalation rates based on commodity supply and demand drivers as described earlier.

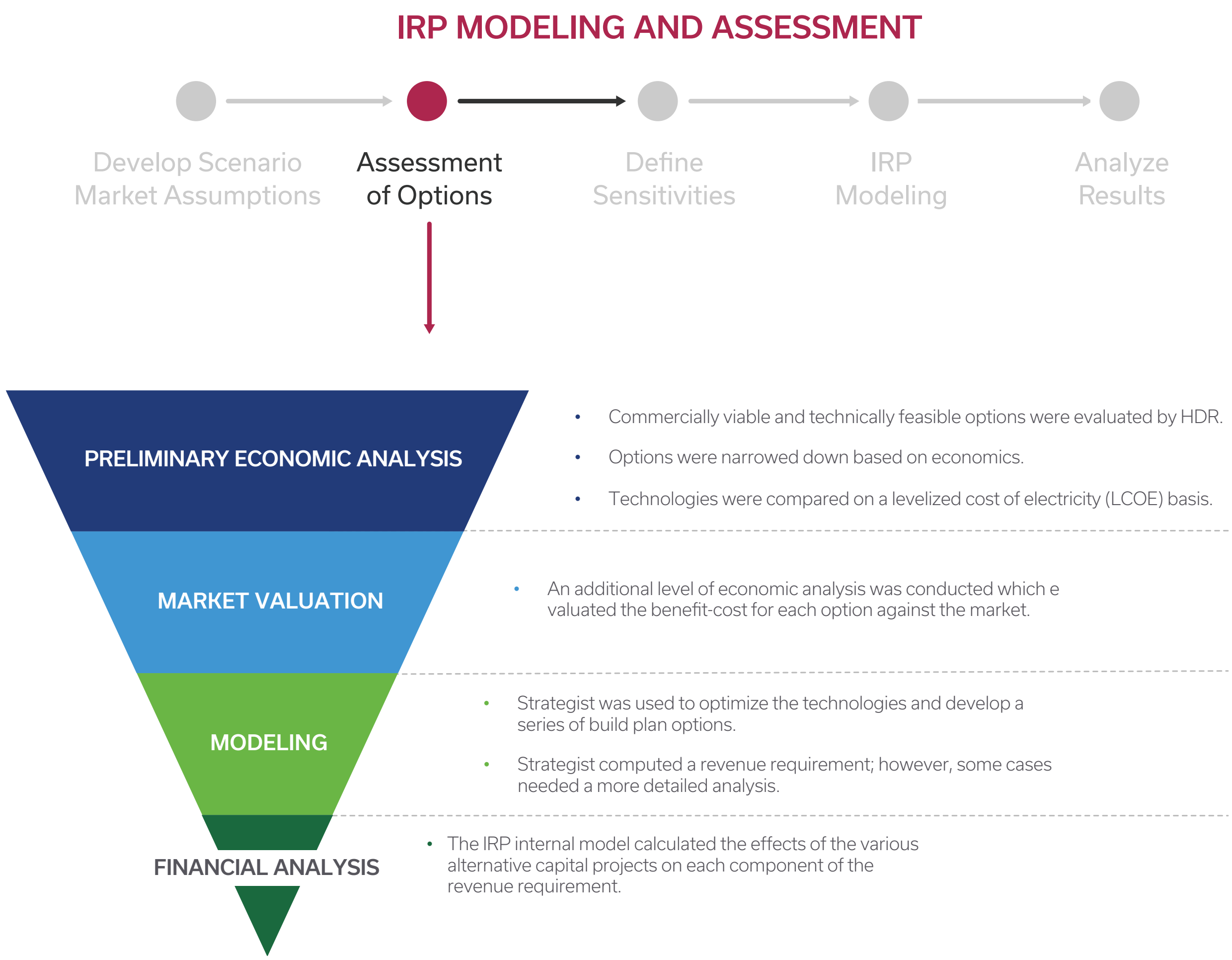
Figure 11.2.9-1

DTE DEFLATOR SERIES



11.3 Assessment of Options

Figure 11.3-1: IRP Modeling and Assessment Process – Assessment of Options



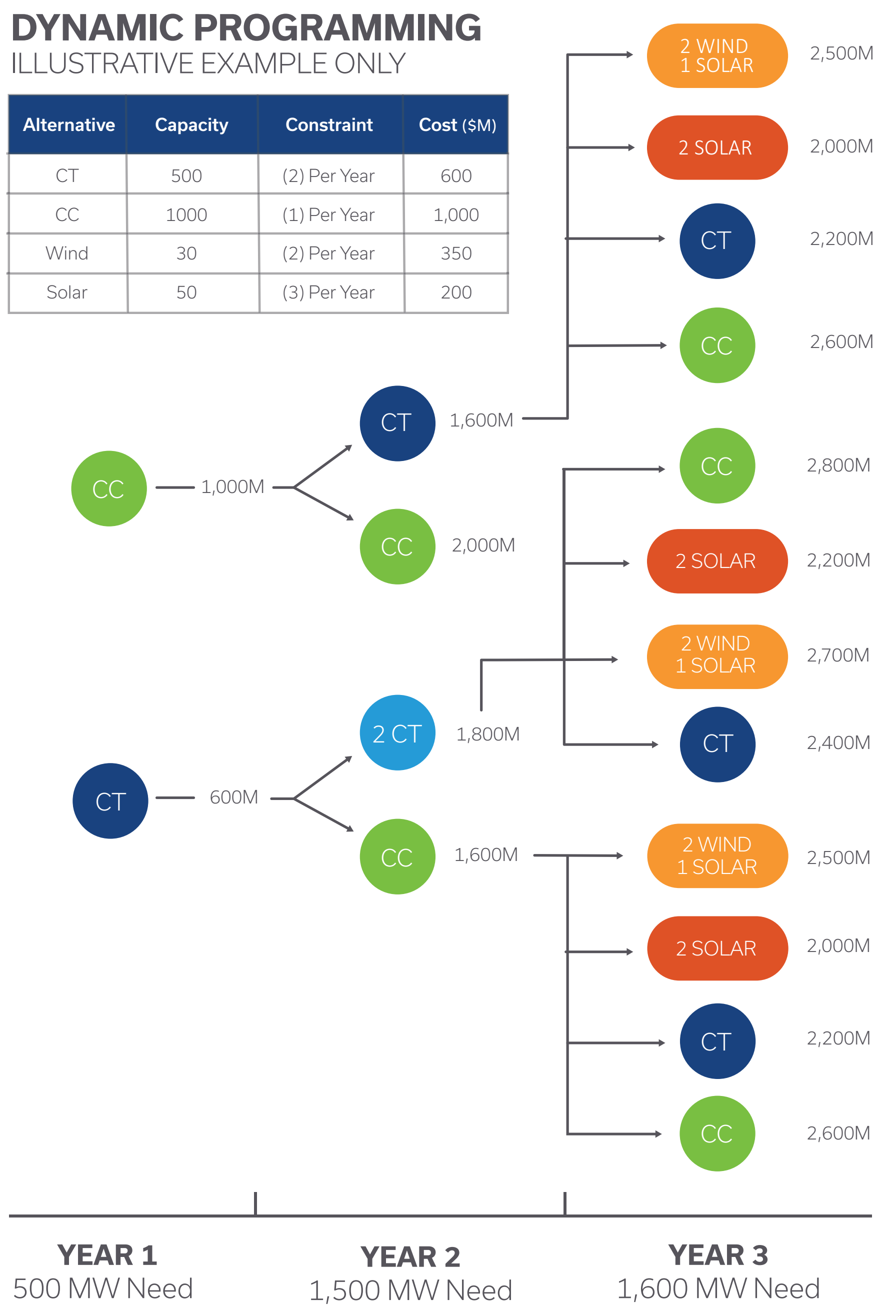
For the assessment of options, as depicted in Figure 11.3-1, the demand-side and supply-side integration began with several alternatives considered for meeting DTEE's future requirements. In addition to those alternatives, DTEE included 300 MW of potential short-term market purchases. For the complete list of supply-side and demand-side alternatives evaluated through IRP modeling, refer to Table 10.10-1.

The IRP modeling used to assess the resource options is complex. Each supply-side and demand-side alternative and its introduction into the resource mix is a considered a mathematical variable. The effect of each alternative multiplies geometrically for each variable for each year that the analysis progresses in time. Many other variables affect each alternative. Each alternative is then compared against every other alternative.

For illustrative purposes, consider the following based on the methodologies used by DTEE in its resource review. Each resource decision has 2^x alternatives: the 2 defines the choices "add the resource" or "do not add the resource"; x represents the number of alternatives. For example, a planning decision with five alternatives will generate 2^5 or 32 branches on a decision tree for Year 1. By Year 2, the decision tree has another geometric progression of 32 branches, yielding 32 x 32 = 1,024 branches. The resource decision cannot be evaluated for decisions made in Year 1 only. Because the number of resource plans or branches grows exponentially, it is important to establish state space that contains the most economical of the feasible plans. That is, all feasible alternative plans should be saved as the program is running to ensure that the most economical plan is not discarded. In Strategist, only 1,250 states are saved in each run; the rest are discarded to ensure modeling run lengths that are easier to work with (less than approximately 48 hours). Five alternatives with no constraints for 18 years would result in an estimated 32^18 = 1.24 x 10^27 branches if the options analysis was permitted to run unconstrained, attempting to analyze all alternatives. That would not be solvable given the 1,250 possible states that can be saved each run. Therefore, it was necessary to judiciously screen the alternatives, set optimization constraints, and scale up some alternatives to produce a prudent, cost-effective, integrated resource portfolio that meets all DTEE's customers' needs.

Figure 11.3-2 provides an example of the decision logic within the Strategist IRP modeling tool.

Figure 11.3-2: Dynamic Programming Illustrative Example



Alternative	Capacity	Constraint	Cost ($M)
CT	500	(2) Per Year	600
CC	1000	(1) Per Year	1,000
Wind	30	(2) Per Year	350
Solar	50	(3) Per Year	200

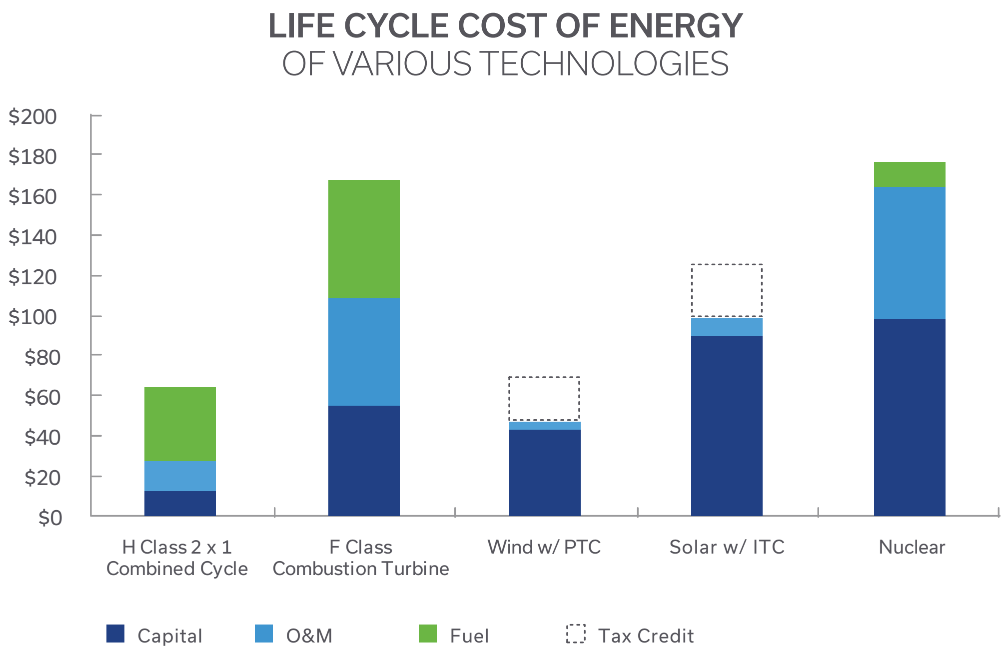
In Figure 11.3-2, in Year 1, there is a 500 MW capacity need. Since the constraints limit the amount of solar and wind that can be built in a given year (2 x 30 MW = 60 MWs of wind and 3 x 50 MW = 150 MWs of solar), states with a combination of wind and solar will be rejected because those plans don't meet the 500 MW need (maximum of 60 MW wind + 150 MW solar = 210 MW). Since a 1000 MW CC or a 500 MW CT plan can solely meet the capacity need, states that build additional capacity beyond a CC or CT will be rejected. Considering Year 2, the saved plans need an additional 500 MW and 1,000 MWs of capacity to satisfy the 1,500 MW need. That is, 500 MW additional needed for the 1000 MW CC plan and 1000 MW additional needed for the 500 MW CT plan. The wind and solar project constraints limit of 210 MWs in each year again limits their additions in Year 2. The addition of 210 MWs in Year 2 is not enough to meet the capacity requirement, therefore only states with the addition of a CC or CT will be saved. In Year 3, an additional 100 MWs is required for each of the saved plans because all four plans from Year 2 total 1,500 MW of capacity. All the alternatives will show up in a saved state in Year 3 due to the fact that the additional need in that year of 100 MW is less than the MW constraint of the alternatives.

Due to the complexity of the dynamic programming model, the resulting resource plans could be exponential or even unsolvable. To prevent this from occurring, DTEE implemented a screening process to limit the number of resource options that go into the more complex modeling phase, to the most technically, commercially, and economically viable resources. The levelized cost of electricity analysis and market valuation are two of the screening processes that DTEE utilized.

11.3.1 LEVELIZED COST OF ELECTRICITY

The LCOE is both an important step in DTEE's screening process as well as an informative metric to compare lifecycle costs of different technologies. Figure 11.3.1-1 shows the LCOE of the Company's prioritized technologies under consideration.

Figure 11.3.1-1



LCOE provides a view of the technology assumptions on a cost basis of the different components of cost. This is particularly helpful when comparing technologies that have common attributes. Levelized cost of electricity is calculated by using the technology input assumptions to forecast the annual costs to operate the technology over its useful life, dividing by the forecasted generation of the unit, and then levelizing the result. The levelizing function takes a varying stream of numbers and reduces them to one value, representing the entire period. Usually costs will be increasing over time; levelization takes these increasing values, discounts them, and expresses the result as one number, usually in the current year dollars. However, there are some limitations to the LCOE comparison.

Comparison to Outside Sources

Since LCOE distills complex assumptions down to one value for each technology type, it is a common method of comparison among technologies. Thus, many organizations calculate LCOE and publish the resulting values. These LCOE calculations can have many differences in the underlying assumptions that make up the final number; some examples include: length of study periods of levelization, base year assumptions, capacity factors assumptions, and financial assumptions regarding owners' costs and financing. Given the range of assumptions, large differences in LCOE calculations can result from different sources. Therefore, it is very important to understand the underlying assumptions when comparing LCOE values calculated by different organizations.

Capacity Factor Effects

The capacity factor is an important component of the LCOE calculation. Some cost components are constant: each MWh produced by the technology will cost the same amount. Fuel is an example of a constant component: the cost per MWh is roughly the same no matter how many MWh are produced by the unit. Also, fixed cost components are in the LCOE: these cost the same amount per year, no matter how many MWh the unit produces. An example of a fixed cost is the capital cost, represented as one lump sum each year; this amount is divided by the energy produced in a year. The more energy produced (higher capacity factors) will drive lower fixed costs on a LCOE basis. Typically, the capacity factor will be the same in all years of the LCOE calculation.

Since the capacity factor is in the denominator of the LCOE, high capacity factor assumptions lead to lower LCOE prices in general. A complication occurs when different technologies tend to operate at different capacity factors, due either to their characteristics (e.g., wind and solar) or how they would be dispatched into the market. For example, combustion turbines (CT) usually run as peakers in the Michigan market with a capacity factor generally in the range of 5 percent to 20 percent. An optimized portfolio will include technologies that vary and cannot always be directly compared with an LCOE analysis. A typical portfolio will need to balance zero-fuel cost renewables with dispatchable resources that are needed for reliability in peak load times.

How Much Value It Is Creating in The Market

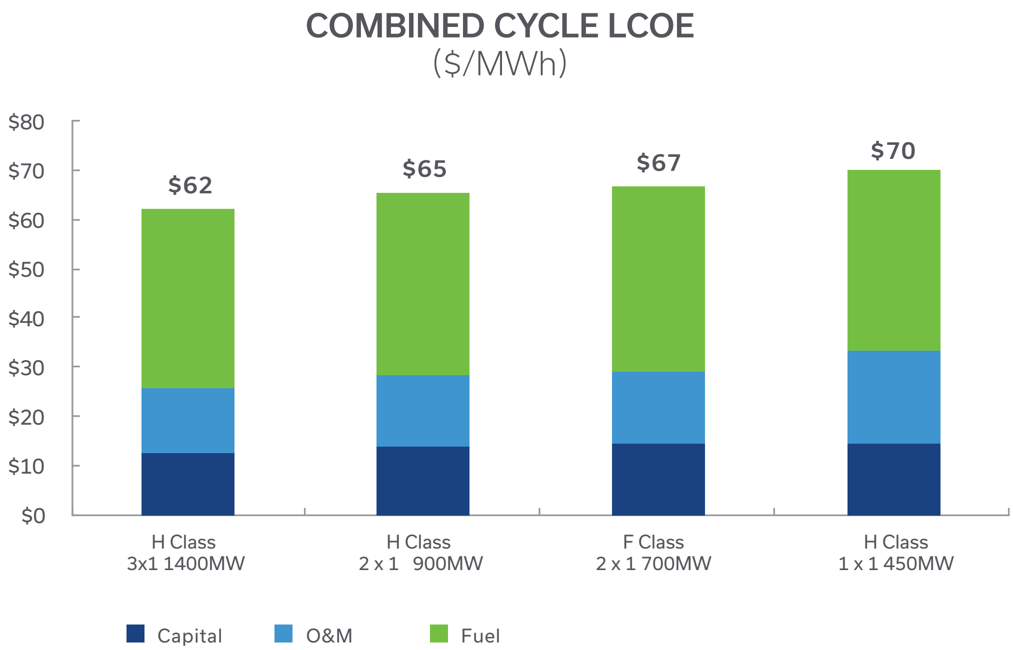
While LCOE is a representation of costs, it does not show how much market value the technology is creating—either in the energy market, the capacity market, or the ancillary services market. The value that the different technologies create in these markets goes right to the bottom line in a revenue requirement view, which is ultimately the cost representation DTEE is using to compare the different resource plans. An example of a technology that looks favorable on a LCOE basis but not on a market value basis is wind. Wind is a low-cost technology compared to gas or gas peakers on an LCOE basis; however, it is not dispatchable, causing adverse effects in all three markets. In the energy market, wind energy has a load shape profile in DTEE's service territory with peak wind production that does not line up with peak load, either seasonally or in a typical day. Therefore, the wind is either excess and sold to the market at low price, or the wind is not blowing during higher cost times, and market purchases must be made at higher costs. In MISO, the wind units get capacity credit based on their historical performance during eight peak times in previous years. Currently, MISO awards a 15.6 percent capacity credit for new wind units. That means that while a 100 MW nameplate wind farm might be capable of 100 MW during a period of sustained wind, the annual performance is an average of 40 MW in any one hour (with a capacity factor of 40 percent). On peak days, the same windfarm has historically produced 15.6 MW during the peak hour. Only 15.6 MW of the 100 MW wind farm is given credit toward the required reserve margin; the rest must be either purchased from the market or supplied by another type of technology. Since wind units are not dispatchable, they have low ancillary service market value. In addition, at high levels of wind penetration, additional integration may be required from other units. The costs for this integration may show up in the ancillary service value for the other types of units, therefore creating a type of negative ancillary value for wind, or added cost for integration.

LCOE was an important step in the IRP screening process because it reduced the number of alternatives to the best of each category (base load, cycling, peaking). DTEE is careful to only compare like technology types when screening and eliminating technologies (e.g., CCGT units were compared to each other, peakers were compared to each other). Since DTEE ensured the calculations were done on a consistent basis, comparison to outside sources was not applicable. The limitation about capacity factors was eliminated when the technologies were compared in groups and the same capacity factor was used for each type of technology. Limitations regarding market value will be accounted for in the next screening step, described in Section 11.3.2.

Combined Cycles

Combined cycle gas turbines were modeled at an 80 percent capacity factor, which is consistent with the results in the Reference scenario. The effect from the economy of scale of the different-sized combined cycles is evident from the LCOE modeling results as shown in Figure 11.3.1-2. Since the heat rates and fuel prices of the different CCGT technologies shown here are similar, the variation in LCOE is primarily attributed to fixed costs allocated across the total project size.

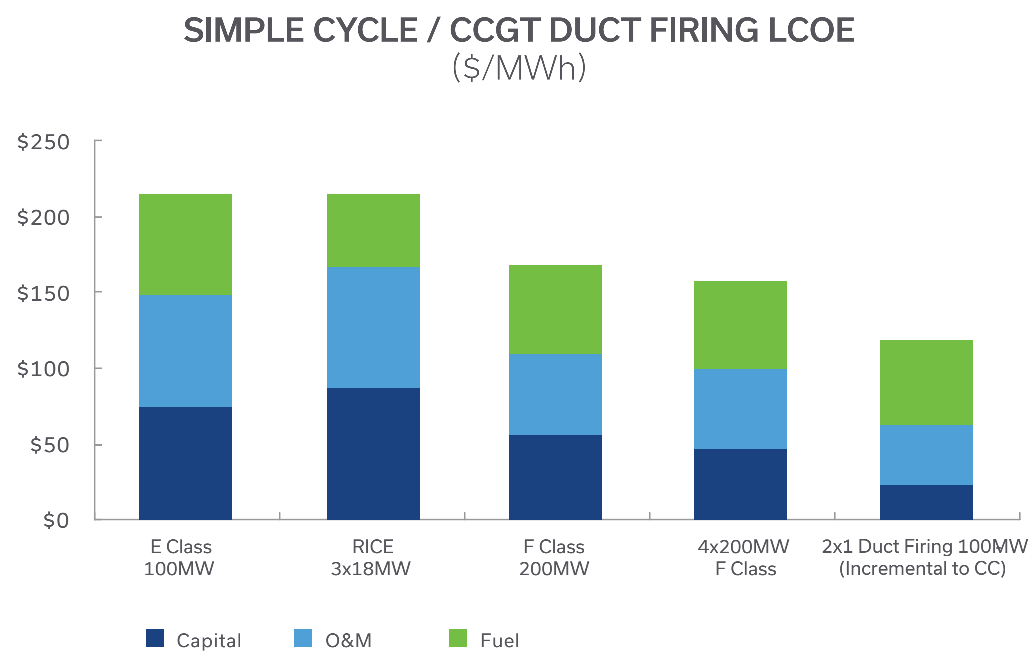
Figure 11.3.1-2



Simple Cycle Units and CCGT Duct Firing

LCOE modeling results for three types of simple cycle units are shown in Figure 11.3.1-3. In addition, for comparison purposes, incremental duct firing on a combined cycle gas turbine is shown. Duct firing is included because it is operated similar to a CT, and is used for peaking capacity. The capacity factor of the CT units is 17 percent while the duct firing option assumes a capacity factor of 35 percent based on dispatch modeling results. The heat rate of the CT units ranges from 9,500 to 11,000 Btu/kWh. There is a cost benefit for building more than one CT unit at a time. Installing duct firing on a new combined cycle is less costly than building a CT. The main drivers that make duct firing on a CCGT more economical are lower capital costs and a better heat rate; these two factors lower the LCOE by $39/MWh compared to the 4xCT configuration.

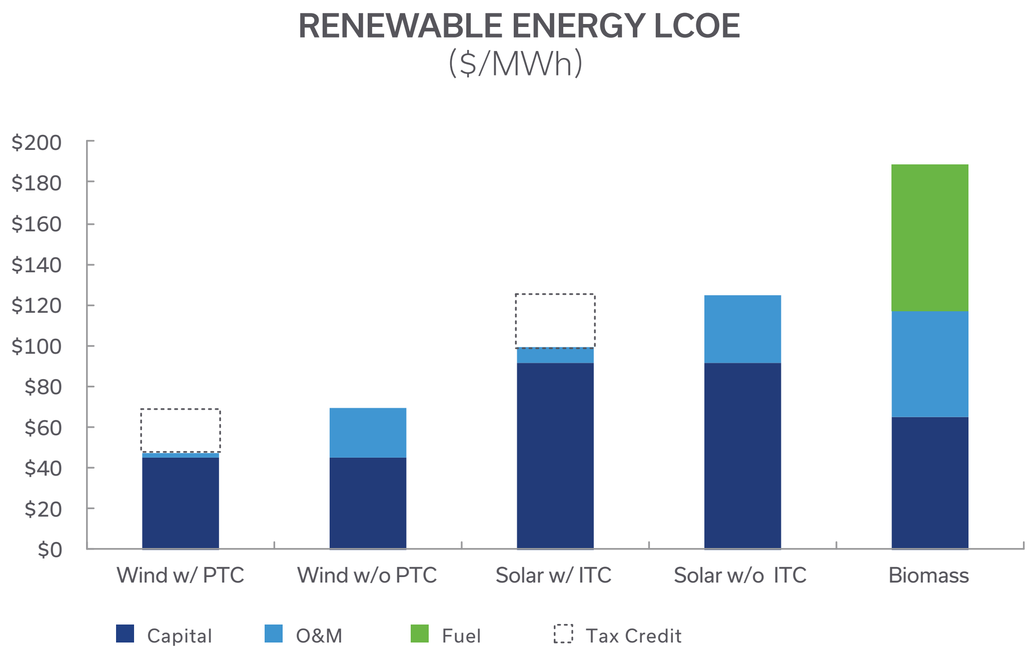
Figure 11.3.1-3



Renewable Energy

LCOE modeling results for various renewable technologies are shown in Figure 11.3.1-4. The value of qualifying for a 100 percent Production Tax Credit (PTC) is approximately $22/MWh on an LCOE basis for a 98 MW wind farm placed in service in 2018. Per current legislation at the federal level, the PTC will phase out with available PTCs stepping down by 20 percent each year starting in 2017. As this subsidy is phased out, the LCOE coming from future wind parks is expected to increase based on the reduced value of the PTCs. The value of the 30 percent Investment Tax Credit (ITC) is approximately $26/MWh on an LCOE basis for a 19 MW solar farm placed in service in 2018. The capacity factor of the wind units shown is 31 percent, the solar units are 20 percent, and the biomass unit is 80 percent.

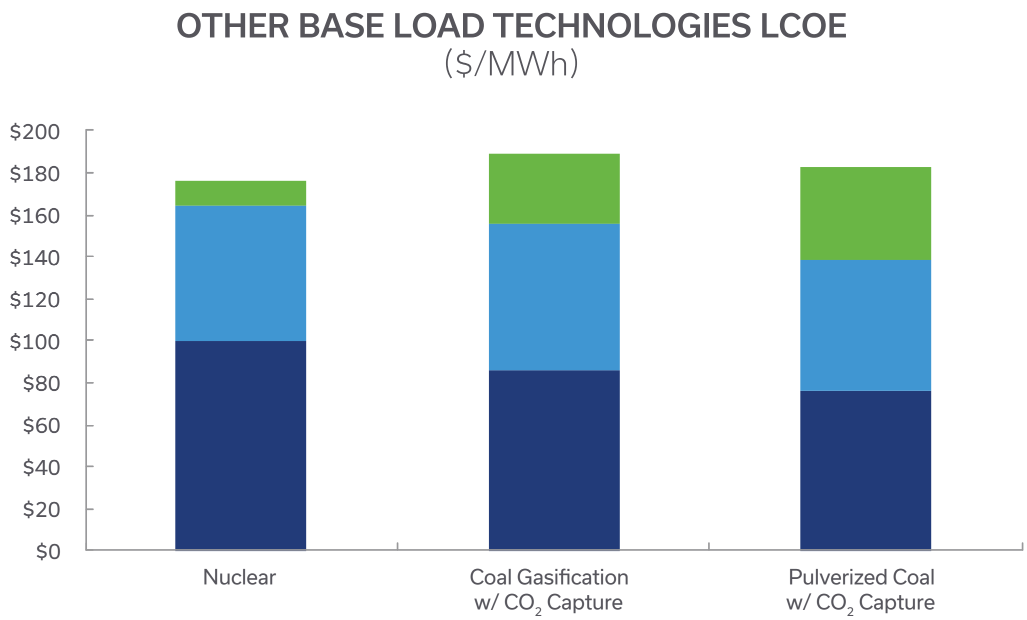
Figure 11.3.1-4



Base Load Technologies

LCOE modeling results for new nuclear and coal units are shown in Figure 11.3.1-5. The capacity factor of the nuclear unit is 93 percent; the pulverized coal technology is 90 percent; and the integrated gasification technology is 80 percent. In addition to being high cost compared with gas CCGT, due to long development and construction times, nuclear is not available until the 2030s, and thus is not a viable option for the first large resource need in this IRP. CCS was expected to be a required technology on new coal units, due to the changing emissions regulations over the last few years, DTEE's announced aspiration of a low carbon future, public perception, and the expected difficulty to obtain environmental permits without low CO_2 technologies. In addition to high costs, CCS technology is still in the developmental stages, making it a risky proposal for DTEE, in conflict with the IRP Planning Principle of reasonable risk. The traditional base load technologies are shown here for completeness. However, due to high costs, higher risk, and long development times, the coal technologies were not considered past the LCOE screening step, and nuclear was considered only in the High Gas Prices scenario in which it may be selected due to high market prices.

Figure 11.3.1-5



11.3.2 MARKET VALUATION SCREENING

After screening IRP alternatives by LCOE, the market value of an alternative was analyzed through a market valuation process. Associated market value calculated for each alternative was useful in screening out options and providing a standard basis for comparing technologies. A market valuation was created by comparing the outputs of two Strategist runs. The first Strategist run purchases future energy and capacity needs from the market. The second run places into service the desired resource being evaluated. These runs were done with the scenario market data loaded into the Strategist modeling tool, but prior to resource optimization (described in Section 11.5). The benefit and costs of the resource being evaluated (Figure 11.3.2-1) were then compared to purchasing the equivalent energy and capacity from the market. A benefit-cost ratio is determined by dividing the discounted benefit by the discounted cost of an asset. Given the market energy and capacity price forecast, a value of greater than one would indicate that the total benefits outweigh the total cost for that alternative. Numbers below one could indicate that the market price projections for capacity and energy for that technology might not support pure merchant generation options.

Figure 11.3.2-1: Market Valuation

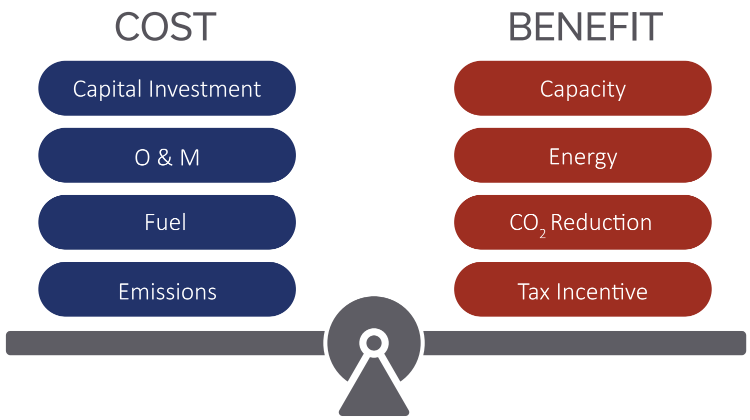


Table 11.3.2-1: Market Valuation Results

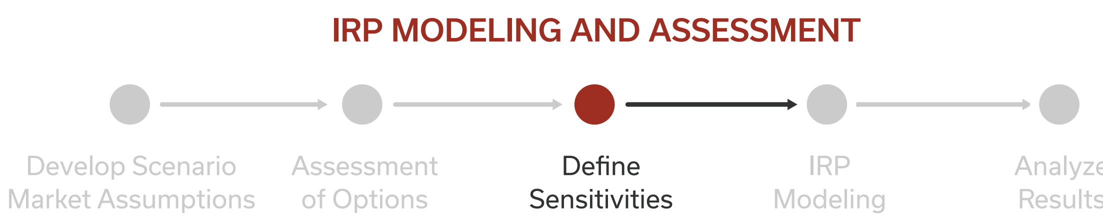
		Reference	High Gas	Low Gas	Emerging Tech	AggressiveCO_2
NATURAL GAS	1 x 1 H Class CCGT	0.85	0.91	0.80	0.84	0.86
	2x 1 H Class CCGT	0.92	0.93	0.87	0.91	0.93
	3x 1 H Class CCGT	0.95	0.94	0.90	0.94	0.96
	2 x 1 F Class CCGT	0.87	0.90	0.82	0.86	0.88
	Frame 7 CT	0.74	0.75	0.66	0.72	0.70
RENEWABLE	Solar	0.59	0.69	0.51	0.55	0.62
	Wind	0.75	0.88-1.05[1]	0.67	0.73	0.83
	Lithium Ion Battery	0.26	0.19	0.21	0.23	0.24
DEMAND RESPONSE	Behavioral	0.69	0.42	0.43	0.63	0.63
	Thermostat	0.79	0.40	0.56	0.66	0.71
	BYO Thermostat	0.73	0.37	0.48	0.62	0.66

[1]Based on capacity factors ranging from 35%-41%.

Table 11.3.2-1 summarizes the benefit-cost ratios performed across all scenarios. The benefit-cost ratios for different technologies can be compared within the same market scenario, the higher numbers indicating more value for that technology. In almost every scenario, a combined cycle yielded the highest benefit-cost ratio, except for wind in the High Gas Prices scenario. This is partly due to a high energy market resulting from high gas prices and a CO_2 emission price on carbon emitting resources. The 0.88-1.05 range for wind in the High Gas Prices scenario indicates a sensitivity for the capacity factor of wind. The 1.05 ratio assumes that new wind resources would have a capacity factor of 42 percent, while the 0.88 ratio assumes that wind will have a capacity factor of 35 percent. Although current operating wind projects have capacity factors ranging from 29 percent to 45 percent, the capacity factor of future wind projects is expected to be in the low 30 percent range.

11.4 Define Sensitivities

Figure 11.4-1: IRP Modeling and Assessment Process – Define Sensitivities



Sensitivities as depicted in Figure 11.4-1, are DTEE-specific variables that affect only the DTEE service territory and/or Michigan. The sensitivities chosen focused on possible variations that could truly affect the resource decision, such as load changes and lower CO_2 aspirations for DTEE. Most sensitivities were performed on the Reference scenario because that scenario provides a common base to compare each sensitivity with the others. For the other four scenarios, certain sensitivities were completed based upon a judgment regarding whether the varied assumption would affect the optimized portfolio.

Load

The load sensitivities included both a high growth and low growth assumption. In the high growth sensitivity, increased automotive production and data centers are prevalent. The low growth assumed that the unemployment rate is higher, population decreases, and the automotive industry reduces production.

Renewable Energy

The renewable energy sensitivity focused on a high renewable plan in the event that a higher renewable mandate is set. To achieve that target, 1500 MW of renewables in addition to the amount included in the base case are needed.

Energy Efficiency

There were several levels of energy efficiency that were tested as energy efficiency sensitivities. In the Strategist model, the energy efficiency levels described in Section 10.7 were modeled as alternatives using a "transaction alternative." In this way, the hourly shape as well as the costs of each energy efficiency level was fully integrated into the Strategist optimization.

There was a base amount of energy efficiency included in the load forecast. This amount of energy efficiency was levered up or down as appropriate using transaction alternatives representing different levels of energy efficiency.

Combined Cycle Capital Costs and Size

DTEE also wanted to test the capital costs of the optimal resource plan to ensure that even with 20 percent higher costs, it would still be the most economical option. DTEE's analysis determined the combined cycle was the most optimal technology; different size options were also evaluated.

Electric Choice Customer Return

The Electric Choice customer return sensitivities tested what would occur if 50 percent (Commercial) or 100 percent (Commercial and Industrial) Choice customers returned as fully serviced DTEE customers.

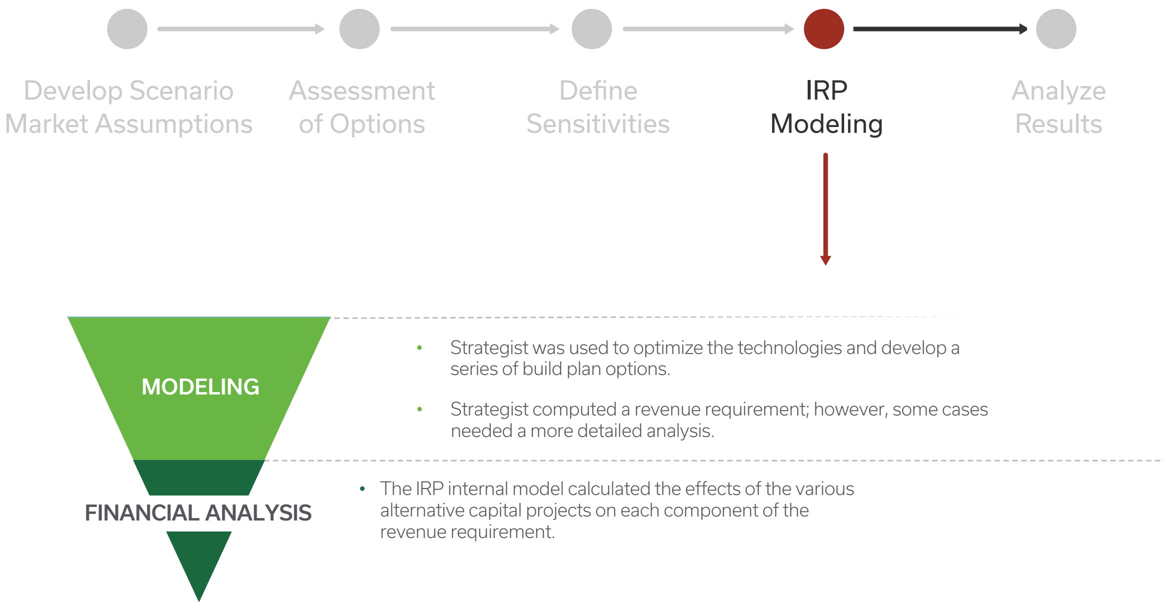
A comprehensive summary of all sensitivities modeled under each scenario is detailed in Table 11.4-1.

Table 11.4-1: Summary of all Sensitivities Modeled

		Reference	High Gas	Emerging Technologies	Low Gas	Aggressive CO_2
Sensitivities	Load	High Growth				
		Low Growth				
	Renewable Energy	High Renewables	High Renewables	High Renewables		
	Energy Efficiency	5 levels of EE	3 levels of EE	3 levels of EE	3 levels of EE	3 levels of EE
	Capital Cost		+20% increase	+20% increase	+20% increase	
	CC Size (vs. 2x1)	H Class 1x1	H Class 3x1	H Class 3x1	H Class 3 x 1	H Class 3x1
		H Class 3 x1				
	Choice	All comes back				
		50% comes back				
	New Nuclear		Nuclear in 2030			
	CO_2		New Sources count			Aggressive CO2 Reduction

11.5 IRP Modeling

Figure 11.5-1: IRP Modeling and Assessment Process – IRP Modeling



11.5.1 MODELING

Strategist Modeling Overview

After the alternatives were screened by type using the LCOE and market valuation analyses, DTEE utilized the energy market simulation tool Strategist, as depicted in Figure 11.5-1, to develop resource plans that meet the forecasted energy and capacity demand. DTEE used four of Strategist's nine application modules: Load Forecast Adjustment (LFA), Generation and Fuel (GAF), PROVIEW (PRV), and Capital Expenditure and Recovery (CER). For more details on Strategist, see Appendix K.

Energy Requirement

To meet DTEE's customers' forecasted energy needs, energy demand was input into the Strategist Load Forecast Adjustment module. In the model, that demand is economically served by a variety of types of resources, including:

1. **Non-dispatch renewable resources (e.g., wind, solar):** Resources were modeled as hourly transactions, equivalent to a system purchase at no cost. Hourly transaction profiles within the database are

based on a representative sample of historical generation.

2. **Dispatched generation (e.g., existing coal, CCGT, CT):** Dispatch pricing of thermal units consists of emission prices (SO_2, CO_2, NO_X), fuel prices, variable O&M, and heat rate. Thermal units are dispatched based on power prices and were modeled differently:

    a. Coal and nuclear units were modeled as must-run units, as they are not designed to cycle online and offline for short periods of time. When power prices dip below the dispatch of must-run units, they will dispatch down to their minimum generation and operate at a marginal loss.

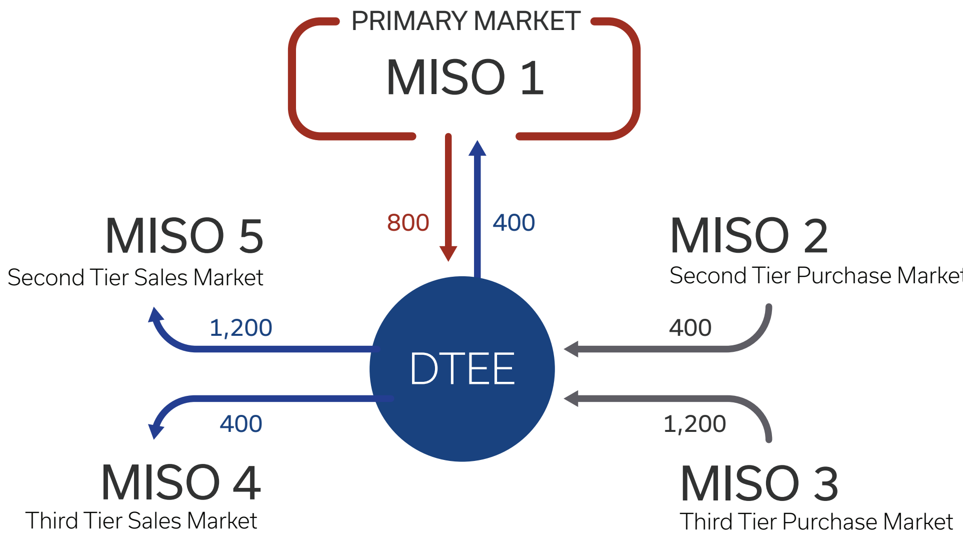
    b. CCGTs and CTs are modeled as economic dispatch units. When market prices drop below the dispatch price of cycling units, they will come offline and the energy needed to support demand will be purchased from the market.

3. **Energy storage technologies (e.g., batteries, pump storage):** Energy storage resources are economically dispatched based the marginal cost of charging during off-peak hours and generating during on-peak hours.

4. **Demand-side resources (e.g., energy efficiency):** Energy efficiency programs were modeled as supply-side alternatives within the GAF to evaluate EE programs on the same basis as other supply-side options. An appropriate reserve margin and transmission loss adjustment was made. Demand response programs were modeled as supply-side alternatives, available in peak load hours to reduce the capacity requirement.

5. **Market purchases:** Hourly market prices were input into the GAF module as five markets to represent a depth of market. Sales and purchases share the same primary market with each having two additional tiers as shown in Figure 11.5.1-1. When purchases or sales exceed the primary market tier capabilities, the second-tier market will set the price for purchases and sales, subsequently followed by the third tier once the second-tier limit is met.

Figure 11.5.1-1 Tiered Market



Capacity Requirement

The capacity demand forecast was calculated using a Planning Reserve Margin (PRM) requirement set by MISO, intended to reliably serve the MISO coincident peak demand for a given year. The reserve margin requirement was input into Strategist as a target in the Generation and Fuel module, and as a max/min margin in PROVIEW. The forecasted reserve margin requirement is served by existing resources through a calculated unforced capacity value (UCAP) from MISO, and the addition of future capacity resources as shown in Table 11.5.1-1.

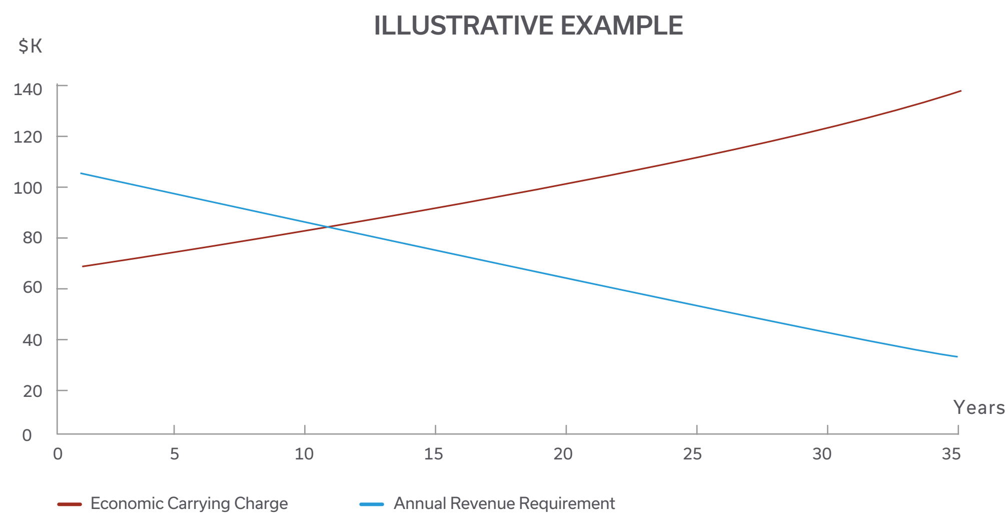
Table 11.5.1-1 Capacity Credit for IRP alternatives

Resource Type	Capacity Credit Methodology
Existing Dispatchable	Calculated by MISO. Capacity credit largely driven by Equivalent Forced Outage Rate-Demand (EFORd) which leads to variance between assets.
New Wind	Calculated by MISO. 15.6% capacity credit for wind.
New Solar PV	Calculated by MISO. 50% capacity credit for solar.
Energy Efficiency	The capacity credit of EE programs is valued at the energy savings realized at the peak hour demand in a given year.
Demand Response	Credited for programs peak capacity reduction.
New Dispatchable	Reduced summer capacity by a representative random outage percentage factor to get a UCAP value.

Optimization

PROVIEW utilized the principle of economic carrying charge (ECC) to capture the value of deferring an alternative in order to accurately account for avoided costs. The ECC represents an annual payment escalating over the life of an asset whose net present value of ECC payments is equal to the net present value revenue requirement. Deferring capital spending when the after-tax weighted cost of capital is greater than inflation is beneficial. The base year revenue requirement used in the ECC calculation was pulled from the Capital Expenditure and Recovery (CER) module. The total net present value lifetime cost for each project was input into the CER to account for a specific schedule of capital expenses.

Figure 11.5.1-2 $1M Rate Base



The discounted costs (area under the curve) are equivalent for the economic carrying charge and Present Value of Revenue Requirement (PVRR) methods of calculation, as depicted in Figure 11.5.1-2. The Present Value of Utility Costs (PVUC) used in the modeling is mathematically equivalent to PVRR.

The PROVIEW module within Strategist evaluated expansion plans that met the PRM requirement and ranked the economics of future plans by calculating a PVUC for each qualifying plan. The PVUC ranking and the magnitude differences among plans were used as data points in choosing a prudent resource plan that is low cost and satisfies future energy and capacity requirements. PROVIEW utilizes a dynamic programming approach to systematically evaluate several alternative combinations that meet the constraints within the model. Strategist modeling constraints are established through the LCOE and market valuation screening, limiting the number of feasible states to below that of the maximum storage capacity of saved states.

PROMOD Modeling

DTEE used PROMOD modeling software developed by ABB to simulate how generating units will dispatch, depending on changes in the market. This is a flexible tool, with many possible applications, including locational marginal price forecasting, environmental analysis, asset valuations, and purchased power agreement evaluations. For more details on PROMOD, see Appendix L.

The Strategist program was run first to determine the most prudent resource plan for a desired scenario/sensitivity. The selected resource plan from Strategist was then transferred to PROMOD and the model was run. The output of PROMOD was then input into the financial model. This process was repeated for several of the scenarios evaluated in the IRP. Changes in these scenarios were captured in PROMOD by changing fuel prices, market prices, and emissions costs. Capacity prices and demand response programs were captured outside of PROMOD within the financial model.

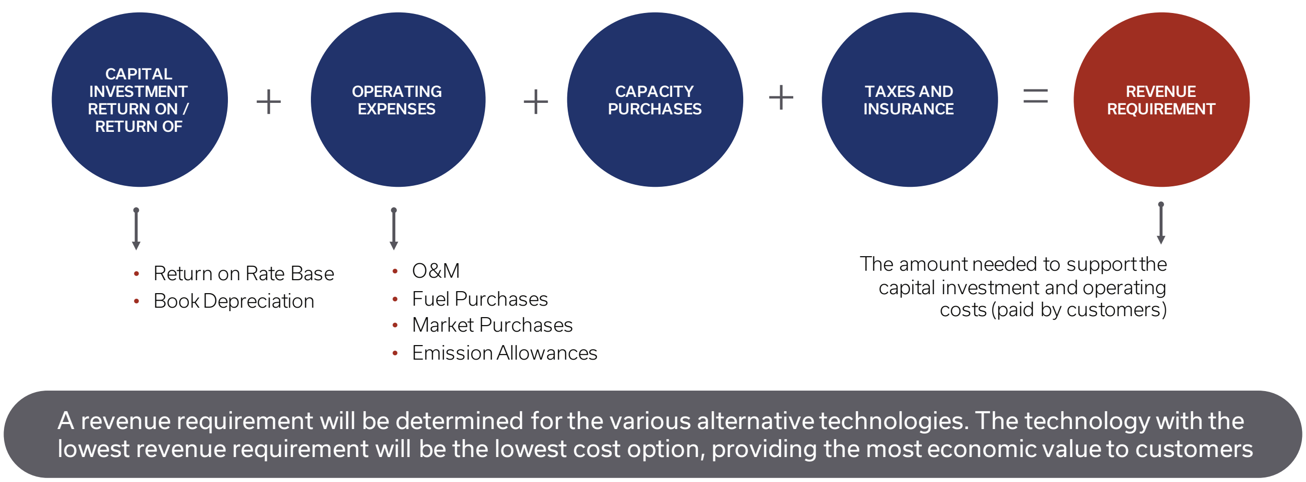
PROMOD was used to produce a full fleet dispatch of various resource plans that had been generated by Strategist; subsequently those results were input to a revenue requirement model to perform full economic modeling of each resource plan/scenario. Both Strategist and PROMOD utilize the Powerbase database to ensure consistency between both models. Many of the inputs within the Strategist LFA and GAF modules not relating to capacity requirements are translated directly from PROMOD through Powerbase.

11.5.2 FINANCIAL ANALYSIS

All scenarios and most of the sensitivities were modeled with Strategist, which ultimately calculated a present value utility cost, similar to the net present value of revenue requirements. The costs loaded into Strategist represented the incremental cost effects of each resource plan being evaluated. Current asset costs were not included because those costs do not affect the new resource decision; they are the same in all cases and therefore cancel out. Knowing the differences in utility costs across various resource plans helped the Company to understand the potential financial outcomes that can affect customers. DTEE wanted to further test resource plans with another layer of analysis to gain a better perspective on the annual revenue requirement effect.

To test the results of the resource plans for key scenarios/sensitivities, the plans were modeled in PROMOD, an hourly dispatch system described in Section 11.5.1. The production cost data resulting from PROMOD was then input into an internal revenue requirement model along with the capital costs of the new technologies and resources to capture the annual effect. The internal revenue requirement model accounts for the capital investment in the form of annual book depreciation expenses and return on capital investment. In addition, operating expenses, fuel purchases, net energy purchases, and emission allowance costs were included in the revenue requirement calculation. Capacity purchases were also taken into consideration, if the resource plan had a capacity shortfall. If the resource plan had surplus capacity, the revenue requirement was reduced by the value of that capacity overage. The property taxes and insurance of the resource alternatives were also included in the revenue requirement calculation. Figure 11.5.2-1 displays the basic concept of the revenue requirement computation.

Figure 11.5.2-1: Annual Revenue Requirement Calculation



For the Reference scenario, the base resource plan and several sensitivity resource plans were selected for the additional layer of analysis. The internal revenue requirement model computed an annual revenue requirement for the resource plans from 2016 to 2040. For the IRP analysis, the base resource plan was compared to sensitivity resource plans and a delta revenue requirement was calculated. The annual stream of delta revenue requirements was then discounted back to 2016. When the base resource plan was the more cost-effective option, the delta would be positive, meaning the alternate portfolio would cost an additional x million dollars. In the case in which a sensitivity resource plan was a better option, the delta would be negative, denoting that the alternative resource plan would save customers x million dollars.

Internal Revenue Requirement Modeling Methodology

In selecting the most viable technology and/or resource, the additional costs customers would have to incur as a result of selecting that technology or resource was assessed. The internal revenue requirement model was designed to evaluate a new technology or resource on a more streamlined basis. The model is considered more of a project revenue requirement, assessing the incremental costs resulting from the addition of the new technology or resource, including the effects to existing generation.

Purpose of the Internal Revenue Requirement Model

The model was developed specifically to evaluate various technology and demand-side management resources. The revenue requirement calculation in this model captures only the potential changes in the revenue requirement components caused by the potential investment.

Internal Revenue Requirement Model Components

The following components are needed for the revenue requirement evaluation of a new technology, demand-side resource, or an asset purchase.

- Return on capital invested: The marginal cost of capital multiplied by the average rate base. The formula for the average rate base is:
- Average Rate Base = (Gross Plant in Service + CWIP-Book Depreciation – Deferred Taxes)
- Book depreciation expenses
- Non-fuel variable O&M of the new resources
- Chemical variable O&M of existing resources (to capture the change in costs related to generation caused by a new resource)
- Fixed O&M of new resources
- Fuel purchases for new and existing resources
- Emission allowances of new and existing resources
- Insurance cost of new resources
- Property tax of new resources
- Net energy purchases
- Net capacity purchases

Certain costs unrelated to the project analyzed were not included in the analysis because they would be the same for the two cases, and thus the delta revenue requirement would be zero. This allowed for a clearer examination of the relevant capital, O&M, and other costs that were analyzed.

Cash Cost of Construction and Allowance for Funds Used During Construction (AFUDC)

For modeling efficiency, the capital effect of the new resource does not go into the revenue requirement calculation until the in-service year. The cash cost of construction and AFUDC will be accrued in construction work in progress (CWIP), then transferred to Plant in Service upon the time of the unit coming online, and then go into rate base.

Cost Recovery

Rate cases are assumed every year.

Deferred Taxes

Deferred taxes are included as a reduction to rate base.

Assumptions

There are various inputs into the internal revenue requirements model in addition to the PROMOD production and the new resource costs.

Financial Ratios

The revenue requirement model used the financial ratios approved in the U-17767 MPSC Rate Order. The pretax marginal cost of capital was used to calculate the return on rate base. The after tax weighted cost of capital was used to calculate the AFUDC. The pre-tax weighted cost of capital was used as the discount rate in calculating the net present value of the annual revenue requirement streams. A complete list of the financial assumptions is shown in Table 11.5.2-1.

Table 11.5.2-1: DTEE Financial Assumptions

Financial Assumptions	U-17767
Long-term Debt	50.00%
Common Equity	50.00%
Cost of Debt (Pre-tax)	4.56%
Cost of Equity (After-tax)	10.30%
Marginal Cost of Capital (After Tax)	7.430%
Marginal Cost of Capital (Pre-Tax)	10.72%
Cost of Capital for AFUDC	5.70%
Discount Rate	8.21%

Book Depreciation

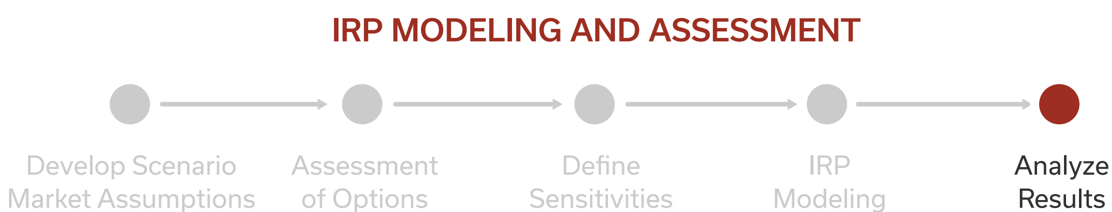
New technologies such as combustion turbines and combined cycles were assumed to have a 30-year life. The wind and solar book deprecation rates were based on the approved U-17667 Rate Order. Based on the energy efficiency filings, 15 percent of EO program spend is capitalized on a five-year straight-line depreciation schedule. Demand response capital investments are depreciated over five years as well.

Tax Depreciation

Modified Accelerated Cost Recovery (MACR) schedules are used for tax depreciation. Combustion turbine and combined cycles are on the 20-year MACR schedule. Renewables and demand response are on a five-year schedule. Energy efficiency is expensed in the year it is incurred.

11.6 Analyze Results

Figure 11.6-1: IRP Modeling and Assessment Process – Analyze Results



For all scenarios, to analyze results, as depicted in Figure 11.6-1, there was a base resource plan that included a H Class 2x1 combined cycle in 2022. The base resource plan also included 1.15 percent energy efficiency savings program and 500 MW of incremental wind and solar units. All the selected resource plans from the various scenario and sensitivities were compared to this base resource plan to test it under the changing assumptions.

11.6.1 STRATEGIST RESULTS

The results of the Strategist optimizations for all scenarios and sensitivities are shown in Tables 11.6.1-1 through 11.6.1-6.

Table 11.6.1-1: Legend of Strategist Alternatives

Short Name	Technology
41X0	4 F7CT build with economy of scale benefit
7EA	GE 7E.03
BDR	Behavioral Demand Response
DR_B	DR - Bring your own thermostat
DRY	2x1 H Class Dry Cooling
EE x%	Energy efficiency savings program
F 2X1	F Class 2x1
F 2X1 D	Duct Fire - F Class 2x1
F7CT	Frame 7 CT
H 1X1	H Class 1x1
H 1x1 D	Duct Fire - H Class 1x1
H 2X1	H Class 2x1
H 2X1 D	Duct Fire - H Class 2x1
H 3X1 D	Duct Fire - H Class 3x1
H 3X1	H Class 3x1
IACB	DR - Interruptible A/C Base
LITH	Lithium ion battery
LM60	GE LM6000
LMS1	GE LMS100
NUKE	Nuclear
PUR	Capacity Purchase
SAGG	Solar - Aggressive Solar Capital
SOLA	Solar
THER	DR- Thermostat
WAGG	Wind - Aggressive Capital
WIND	Wind

Table 11.6.1-2 Strategist Reference Scenario Resource Plan Results

	Base Resource Plan	3x1 in 2022	1x1 in 2022 and 2024	High Renewables	2.0% EE	1.5% EE	1.0% EE	<1.0% EE	High Load Demand	Low Load Demand	Commercial Choice Returns	C&I Choice Returns
2016	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)
	EE 1.15%	EE 1.15%	EE 1.15%	EE 1.15%	EE 2.00%	EE 1.50%	EE 1.00%	EE <1.00%	EE 1.15%	EE 1.15%	EE 1.15%	EE 1.15%
	PUR(92)	PUR(92)	PUR(92)	PUR(93)	PUR(90)	PUR(92)	PUR(92)	PUR(92)	PUR(92)	PUR(92)	PUR(91)	PUR(91)
2017												
2018												
2019												PUR(15)
2020											PUR(257)	PUR(467)
2021											PUR(296)	PUR(545)
2022	H 2X1 (1)	H 3X1(1)	H 1X1 (1)	H 2X1 (1)	PUR(116)	H 2X1 (1)	H 2X1 (1)	H3X1(1)	H3X1(1)	PUR(3)	H 3X1(1)	H 2X1 (1)
	H 2X1 D (1)	H 3X1 D(1)	H 1x1 D (1)	H 2X1 D (1)		H 2X1 D (1)	H 2X1 D (1)	H31D(1)	H31D(1)		H 3X1 D(1)	H 2X1 D (1)
												THER(1)
												PUR(293)
2023	PUR (245)		PUR(756)	PUR(95)	H 2X1 (1)	PUR(103)	THER(1)			H 2X1 (1)	BEHA(2)	H3X1(1)
					H 2X1 D (1)		DR_B(2)			H 2X1 D (1)	THER(1)	H31D(1)
							PUR(295)				DR_B(1)	
											PUR(293)	
2024	PUR(289)		H 1X1 (1)	PUR(104)	PUR(15)	PUR(120)	BEHA(1)				THER(1)	
			H 1x1 D (1)				THER(1)				PUR(297)	
			PUR(292)				DR_B(1)					
							PUR(299)					
2025	PUR(252)		PUR(255)	PUR(17)	PUR(39)	PUR(93)	PUR(276)				PUR(259)	
2026	PUR(248)		PUR(251)		PUR(99)	PUR(127)	PUR(290)				PUR(255)	

	Base Resource Plan	3x1 in 2022	1x1 in 2022 and 2024	High Renewables	2.0% EE	1.5% EE	1.0% EE	<1.0% EE	High Load Demand	Low Load Demand	Commercial Choice Returns	C&I Choice Returns
2027	PUR(231)		PUR(234)		PUR(147)	PUR(151)	PUR(298)	PUR(43)			PUR(238)	
2028	PUR(215)		PUR(218)		PUR(197)	PUR(197)	DR_B(1)	PUR(93)			PUR(246)	
							PUR(300)					
2029	H 2X1 (1)	PUR(176)	H 2X1 (1)	PUR(297)	H 2X1 (1)	H 2X1 (1)	H 2X1 (1)	H 2X1 (1)	H 2X1 (1)		H 2X1 (1)	PUR(2)
	H 2X1 D (1)		H 2X1 D (1)		H 2X1 D (1)	H 2X1 D (1)	H 2X1 D (1)	H 2X1 D (1)	H 2X1 D (1)		H 2X1 D (1)	
2030	PUR(160)	H 1X1 (1)	PUR(163)	H 1X1 (1)	PUR(267)	PUR(267)	BEHA(1)	PUR(167)		PUR(284)	PUR(190)	F7CT(1)
		H 1x1 D (1)		H 1x1 D (1)			PUR(298)					PUR(274)
		PUR(158)		PUR(228)								
2031	PUR(148)	PUR(146)	PUR(151)	PUR(215)	PUR(258)	PUR(258)	PUR(286)	PUR(155)		PUR(224)	PUR(180)	PUR(263)
2032	PUR(121)	PUR(120)	PUR(124)	PUR(189)	PUR(234)	PUR(234)	PUR(275)	PUR(128)		PUR(150)	PUR(161)	PUR(237)
2033	PUR(112)	PUR(111)	PUR(115)	PUR(179)	PUR(300)	PUR(251)	PUR(269)	PUR(117)		PUR(94)	PUR(152)	PUR(228)
2034	PUR(94)	PUR(92)	PUR(97)	PUR(161)	F7CT(1)	PUR(252)	PUR(242)	PUR(94)		PUR(29)	PUR(133)	PUR(211)
					PUR(135)							
2035	PUR(72)	PUR(71)	PUR(75)	PUR(139)	PUR(89)	PUR(182)	PUR(222)	PUR(67)	PUR(1)		PUR(111)	PUR(189)
2036	PUR(49)	PUR(47)	PUR(52)	PUR(116)	PUR(156)	PUR(225)	PUR(171)	PUR(23)	PUR(16)		PUR(88)	PUR(208)
2037	PUR(21)	PUR(19)	PUR(24)	PUR(88)	PUR(238)	PUR(262)	PUR(166)		PUR(32)		PUR(101)	PUR(181)
2038				PUR(59)	PUR(322)	PUR(212)	PUR(149)		PUR(58)		PUR(113)	PUR(153)
2039				PUR(63)	PUR(295)	PUR(158)	PUR(132)		PUR(128)		PUR(116)	PUR(157)
2040			PUR(1)	PUR(64)	PUR(256)	PUR(99)	PUR(120)		PUR(215)		PUR(118)	PUR(160)
PV UTILITY COST DIFFERENCE ($000)		-35,158	197,922	421,543	-1,067,505	-1,004,090	-447,877	-165,500	537,087	-2,073,400	1,469,122	2,555,394

Table 11.6.1-2, and similar tables for the other scenarios are used in conjunction with the legend shown in Table 11.6.1-1. Table 11.6.1-2 contains the years of study down the far-left column and that year's selected resources for each sensitivity. The base resource plan is the next column on the left, followed by columns with the resource plans for the other sensitivities modeled for the Reference scenario. In the base resource plan for 2016, "IACB (1)," "EE 1.15%," and "PUR(92)" are listed. Using Table 11.6.1-1, interpret this to mean that in 2016, DR-Interruptible IAC Base, the 1.15 percent energy efficiency amount, and 92 MW of capacity purchase occur. Similar interpretations for the other years of study across all the sensitivities use Table 11.6.1-1.

Under the Reference scenario, the base resource plan assumes a 2x1 H Class combined cycle in 2022 and 1.15 percent energy efficiency savings. There were several sensitivities completed on the Reference scenario.

- One of the sensitivities tested building a 3x1 H Class combined cycle in 2022. The results indicated that the larger combined cycle had a lower PVUC. However, DTEE ultimately selected the 2x1 H Class after considering the additional Planning Principles described in Section 4. The 3x1 H Class would exceed the capacity need of the Company and does not become more valuable than the 2x1 combined cycle until late in the study period, meaning that customers would pay more throughout most of the study period.
- In most of the remaining sensitivities, the 2x1 H Class combined cycle was selected except for the higher load cases. With the higher load sensitivities, the 3x1 H Class combined cycle was selected because it accommodated the higher demand. For more information regarding the potential risk, refer to Section 12 Risk Assessment.
- For the energy efficiency sensitivities, the 2.0 percent program showed a slightly lower PVUC in Strategist over the 1.5 percent EE savings program. However, the 1.5 percent program was selected based on further evaluation using the detailed revenue requirements modeling (shown in Section 11.6.2) and other program considerations including lowest UCT cost (discussed in Section 10.7).

Table 11.6.1-3: Strategist High Gas Price Scenario Portfolio Results

	Base Resource Plan	New Source Complement	3x1 in 2022	High Renewables	1.5% EE	1.0% EE	Nuclear in 2030	Capital Increase on CCs
2016	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)
	EE 1.15%	EE 1.15%	EE 1.15%	EE 1.15%	EE 1.5%	EE 1.00%	EE 1.15%	EE 1.15%
	PUR(92)	PUR(92)	PUR(92)	PUR(93)	PUR(92)	PUR(92)	PUR(92)	PUR(92)
2017								
2018								
2019								
2020								
2021								

	Base Resource Plan	New Source Complement	3x1 in 2022	High Renewables	1.5% EE	1.0% EE	Nuclear in 2030	Capital Increase on CCs
2022	H 2X1 (1)	H 2X1 (1)	H 3X1(1)	H 2X1 (1)	W22 (1)	H 2X1 (1)	H 2X1 (1)	H 2X1 (1)
	H 2X1 D (1)	H 2X1 D (1)	H 3X1 D(1)	H 2X1 D (1)	PUR(200)	H 2X1 D (1)	H 2X1 D (1)	H 2X1 D (1)
2023	PUR(245)	PUR(245)		PUR(95)	7HA2(1)	THER(1)	PUR(245)	PUR(245)
					H21D(1)	DR_B(2)		
						PUR(295)		
2024	PUR(289)	PUR(289)		PUR(104)		BEHA(1)	PUR(289)	PUR(289)
						THER(1)		
						DR_B(1)		
						PUR(299)		
2025	PUR(252)	PUR(252)		PUR(17)		PUR(276)	PUR(252)	PUR(252)
2026	PUR(248)	PUR(248)				PUR(290)	PUR(248)	PUR(248)
2027	PUR(231)	PUR(231)				PUR(298)	PUR(231)	PUR(231)
2028	PUR(215)	PUR(215)			PUR(41)	DR_B(1)	PUR(215)	PUR(215)
						PUR(300)		
2029	H 2X1 (1)	H 2X1 (1)	PUR(176)	PUR(297)	7HA2(1)	H 2X1 (1)	LITH(1)	H 2X1 (1)
	H 2X1 D (1)	H 2X1 D (1)			H21D(1)	H 2X1 D (1)	S29 (1)	H 2X1 D (1)
							W29 (1)	
							PUR(252)	
2030	PUR(160)	PUR(160)	F7CT(1)	H 1X1 (1)	PUR(111)	BEHA(1)	NUKE(1)	PUR(160)
			W30 (1)	H 1x1 D (1)		PUR(298)		
			PUR(291)	PUR(228)				
2031	PUR(148)	PUR(148)	PUR(279)	PUR(215)	PUR(102)	PUR(286)		PUR(148)
2032	PUR(121)	PUR(121)	PUR(253)	PUR(189)	PUR(78)	PUR(275)		PUR(121)
2033	PUR(112)	PUR(112)	PUR(243)	PUR(179)	PUR(94)	PUR(269)		PUR(112)
2034	PUR(94)	PUR(94)	PUR(225)	PUR(161)	PUR(96)	PUR(242)		PUR(94)
2035	PUR(72)	PUR(72)	PUR(203)	PUR(139)	PUR(90)	PUR(222)		PUR(72)
2036	PUR(49)	PUR(49)	PUR(180)	PUR(116)	PUR(80)	PUR(171)		PUR(49)
2037	PUR(21)	PUR(21)	PUR(152)	PUR(88)	PUR(86)	PUR(166)		PUR(21)
2038			PUR(124)	PUR(59)	PUR(85)	PUR(149)		
2039			PUR(127)	PUR(63)	PUR(116)	PUR(132)		
2040			PUR(129)	PUR(64)	PUR(108)	PUR(120)		
PV UTILITY COST DIFFERENCE ($000)		**-257,068**	**-179,062**	**-156,056**	**-1,475,055**	**-374,028**	**2,038,150**	**246,028**

In the High Gas Prices scenario, the base resource plan was modeled with the 2x1 H Class combined cycle in

2022 and the 1.15 percent energy efficiency program. Seven sensitivities were completed to test the effect of higher gas prices.

- The 3x1 H Class combined cycle had a lower PVUC than the 2x1 H Class; however, it remains an inadequate fit for similar reasons described under the reference case results.
- The high renewables sensitivity assumed 1500 MW of wind and solar in addition to the assumption in the base. The higher renewable sensitivity was more expensive because it did not replace the first 2x1 H Class combined cycle build, which was still the most economical option; additionally, there were incremental costs to build the 1500 MW of renewables.
- The 1.5 percent energy efficiency case had a lower PVUC than the base 1.15 percent program.
- Under the scenario of higher gas prices, building a nuclear plant in 2030 yielded a higher PVUC than the reference case.
- The last sensitivity tested the combined cycle under the assumption that capital costs would increase by 20 percent while the other competing resources remained at the same cost. However, even under these circumstances, the combined cycle was again proven to be the most cost effective technology.

Table 11.6.1-4: Strategist Low Gas Priced Scenario Portfolio Results

	Base Resource Plan	3x1 in 2022	1.5% EE	1.0% EE	Capital Increase on CCs
2016	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)
	EE 1.15%	EE 1.15%	EE 1.5%	EE 1.00%	EE 1.15%
	PUR(92)	PUR(92)	PUR(92)	PUR(92)	PUR(92)
			PUR(		
2017					
2018					
2019					
2020					
2021					
2022	H 2X1 (1)	H3X1(1)	7HA2(1)	H 2X1 (1)	H 2X1 (1)
	H 2X1 D (1)	H3X1 D (1)	H21D(1)	H 2X1 D (1)	H 2X1 D (1)
2023	PUR(245)		PUR(103)	THER(1)	PUR(245)
				DR_B(2)	
				PUR(295)	
2024	PUR(289)		PUR(120)	BEHA(1)	PUR(289)
				THER(1)	
				DR_B(1)	

	Base Resource Plan	3x1 in 2022	1.5% EE	1.0% EE	Capital Increase on CCs
				PUR(299)	
2025	PUR(252)		PUR(93)	PUR(276)	PUR(252)
2026	PUR(248)		PUR(127)	PUR(290)	PUR(248)
2027	PUR(231)		PUR(151)	PUR(298)	PUR(231)
2028	PUR(215)		PUR(197)	DR_B(1)	PUR(215)
				PUR(300)	
2029	H 2X1 (1)	PUR(176)	7HA2(1)	H 2X1 (1)	H 2X1 (1)
	H 2X1 D (1)		H21D(1)	H 2X1 D (1)	H 2X1 D (1)
2030	PUR(160)	BEHA(2)	PUR(267)	BEHA(1)	PUR(160)
		F7CT(1)		PUR(298)	
		THER(3)			
		PUR(300)			
2031	PUR(148)	PUR(288)	PUR(258)	PUR(286)	PUR(148)
2032	PUR(121)	PUR(262)	PUR(234)	PUR(275)	PUR(121)
2033	PUR(112)	PUR(252)	PUR(251)	PUR(269)	PUR(112)
2034	PUR(94)	PUR(234)	PUR(252)	PUR(242)	PUR(94)
2035	PUR(72)	PUR(237)	PUR(247)	PUR(222)	PUR(72)
2036	PUR(49)	PUR(213)	PUR(236)	PUR(171)	PUR(49)
2037	PUR(21)	PUR(185)	PUR(242)	PUR(166)	PUR(21)
2038		PUR(157)	PUR(241)	PUR(149)	
2039		PUR(160)	PUR(272)	PUR(132)	
2040		PUR(162)	PUR(264)	PUR(120)	
PV UTILITY COST DIFFERENCE ($000)		**-68,135**	**-990,573**	**-479,589**	**246,027**

Four sensitivities were modeled under the Low Gas Prices scenario.

- The 3x1 H Class combined cycle had a lower PVUC than the 2x1 H Class; however, it remains an inadequate fit for similar reasons described under the reference case results.
- The energy efficiency sensitivities found that the 1.5 percent energy efficiency case had a lower PVUC than the base 1.15 percent program.
- Increasing the combined cycle capital by 20 percent in the final sensitivity resulted in the combined cycle remaining the most economical technology option.

Table 11.6.1-5: Strategist Emerging Technology Scenario Portfolio Results

	Base Resource Plan	3x1 in 2022	High Renewables	1.5% EE	1.0% EE	Capital Increase on CCs
2016	IACB (1)	IACB (1)	IACB (1)	IACB (1)	IACB (1)	IACB(1)
	EE 1.15%	EE 1.15%	EE 1.15%	EE 1.5%	EE 1.00%	EE 1.15%
	PUR(92)	PUR(92)	PUR(93)	PUR(92)	PUR(92)	PUR(92)
2017						
2018						
2019						
2020						
2021						
2022	H 2X1 (1)	H3X1(1)	H 2X1 (1)	7HA2(1)	H 2X1 (1)	H 2X1 (1)
	H 2X1 D (1)	H3X1 D (1)	H 2X1 D (1)	H21D(1)	H 2X1 D (1)	H 2X1 D (1)
2023	PUR(245)		PUR(95)	PUR(103)	THER(1)	PUR(245)
					DR_B(2)	
					PUR(295)	
2024	PUR(289)		PUR(104)	PUR(120)	BEHA(1)	PUR(289)
					THER(1)	
					DR_B(1)	
					PUR(299)	
2025	PUR(252)		PUR(17)	PUR(93)	PUR(276)	PUR(252)
2026	PUR(248)			PUR(127)	PUR(290)	PUR(248)
2027	PUR(231)			PUR(151)	PUR(298)	PUR(231)
2028	PUR(215)			PUR(197)	DR_B(1)	PUR(215)
					PUR(300)	
2029	H 2X1 (1)	PUR(176)	PUR(297)	7HA2(1)	H 2X1 (1)	H 2X1 (1)
	H 2X1 D (1)			H21D(1)	H 2X1 D (1)	H 2X1 D (1)
2030	PUR(160)	H 1X1 (1)	H 1X1 (1)	PUR(267)	BEHA(1)	PUR(160)
		H 1x1 D (1)	H 1x1 D (1)		PUR(298)	
		PUR(158)	PUR(228)			
2031	PUR(148)	PUR(146)	PUR(215)	PUR(258)	PUR(286)	PUR(148)
2032	PUR(121)	PUR(120)	PUR(189)	PUR(234)	PUR(275)	PUR(121)
2033	PUR(112)	PUR(111)	PUR(179)	PUR(251)	PUR(269)	PUR(112)

	Base Resource Plan	3x1 in 2022	High Renewables	1.5% EE	1.0% EE	Capital Increase on CCs
2034	PUR(94)	PUR(92)	PUR(161)	PUR(252)	PUR(242)	PUR(94)
2035	PUR(72)	PUR(71)	PUR(139)	PUR(247)	PUR(222)	PUR(72)
2036	PUR(49)	PUR(47)	PUR(116)	PUR(236)	PUR(171)	PUR(49)
2037	PUR(21)	PUR(19)	PUR(88)	PUR(242)	PUR(166)	PUR(21)
2038			PUR(59)	PUR(241)	PUR(149)	
2039			PUR(63)	PUR(272)	PUR(132)	
2040			PUR(64)	PUR(264)	PUR(120)	
PV UTILITY COST DIFFERENCE ($000)		**-32,771**	**479,206**	**-1,007,469**	**-464,231**	**246,033**

Five sensitivities were modeled under the Emerging Technology scenario.

- The 3x1 H Class combined cycle had a lower PVUC than the 2x1 H Class; however, it remains an inadequate fit for similar reasons described under the reference case results.
- Under the high renewables sensitivity, it was more expensive to invest in an additional 1500 MW of renewable resources.
- The energy efficiency sensitivities found that the 1.5 percent energy efficiency case had a lower PVUC than the base 1.15 percent program.
- Increasing the combined cycle capital by 20 percent in the final sensitivity resulted in the combined cycle remaining the most economical technology option.

Table 11.6.-1-6: Strategist Aggressive CO_2 Scenario Portfolio Results

	Base Resource Plan	3x1 in 2022	1.5% EE	1.0% EE	Aggressive CO_2 Reduction
2016	IACB(1)	IACB(1)	IACB(1)	IACB(1)	IACB(1)
	EE 1.15%	EE 1.15%	EE 1.5%	EE 1.00%	EE 1.15%
	PUR(92)	PUR(92)	PUR(92)	PUR(92)	PUR(92)
2017					
2018					
2019					
2020					
2021					
2022	H 2X1 (1)	H3X1(1)	7HA2(1)	H 2X1 (1)	H 2X1 (1)
	H 2X1 D (1)	H3X1 D (1)	H21D(1)	H 2X1 D (1)	H 2X1 D (1)

	Base Resource Plan	3x1 in 2022	1.5% EE	1.0% EE	Aggressive CO_2 Reduction
2023	PUR(245)		PUR(103)	THER(1)	PUR(245)
				DR_B(2)	
				PUR(295)	
2024	PUR(289)		PUR(120)	BEHA(1)	PUR(289)
				THER(1)	
				DR_B(1)	
				PUR(299)	
2025	PUR(252)		PUR(93)	PUR(276)	PUR(252)
2026	PUR(248)		PUR(127)	PUR(290)	PUR(248)
2027	PUR(231)		PUR(151)	PUR(298)	PUR(231)
2028	PUR(215)		PUR(197)	DR_B(1)	PUR(215)
				PUR(300)	
2029	H 2X1 (1)	PUR(176)	7HA2(1)	H 2X1 (1)	H 2X1 (1)
	H 2X1 D (1)		H21D(1)	H 2X1 D (1)	H 2X1 D (1)
2030	PUR(160)	H 1X1 (1)	PUR(267)	BEHA(1)	PUR(160)
		H 1x1 D (1)		PUR(298)	
		PUR(158)			
2031	PUR(148)	PUR(146)	PUR(258)	PUR(286)	PUR(148)
2032	PUR(121)	PUR(120)	PUR(234)	PUR(275)	PUR(121)
2033	PUR(112)	PUR(111)	PUR(251)	PUR(269)	PUR(112)
2034	PUR(94)	PUR(92)	PUR(252)	PUR(242)	PUR(94)
2035	PUR(72)	PUR(71)	PUR(247)	PUR(222)	H3X1(1)
					H3X1 D (1)
2036	PUR(49)	PUR(47)	PUR(236)	PUR(171)	
2037	PUR(21)	PUR(19)	PUR(242)	PUR(166)	
2038			PUR(241)	PUR(149)	
2039			PUR(272)	PUR(132)	
2040			PUR(264)	PUR(120)	
PV UTILITY COST DIFFERENCE ($000)		**-35,255**	**-1,001,272**	**-431,232**	**222,140**

The final scenario, Aggressive CO_2, modeled four sensitivities.

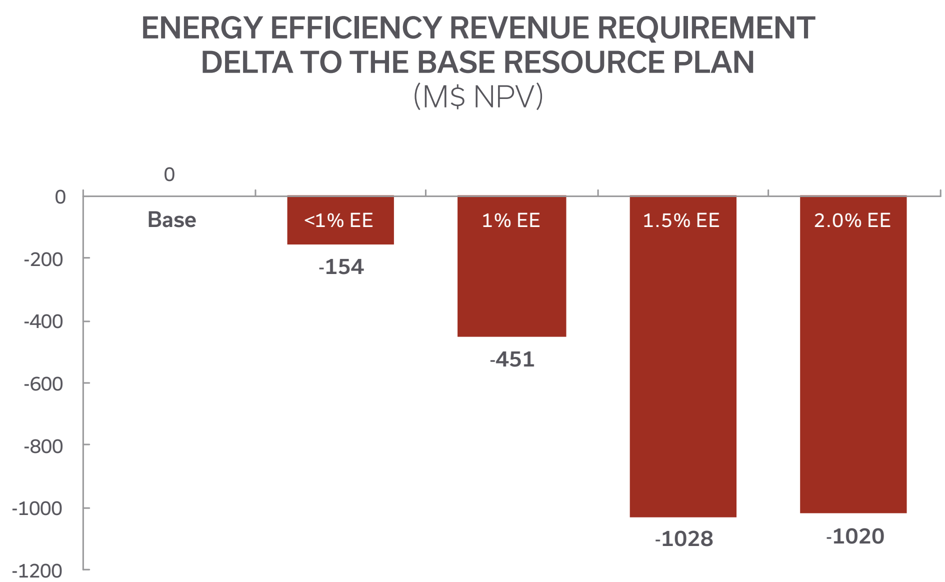
- The 3x1 H Class combined cycle had a lower PVUC than the 2x1 H Class; however, it remains an inadequate fit for similar reasons described under the reference case results.
- For the energy efficiency sensitivities, the 1.5 percent energy efficiency case had a lower PVUC than the base 1.15 percent program.
- Under the Aggressive CO_2 Reduction sensitivity, the CO_2 regulations become more stringent and to get below the required CO_2 emission threshold, assumed to be on a mass basis with no trading allowed,

the retirement of the Monroe power plant is needed by 2037.

11.6.2 REVENUE REQUIREMENT RESULTS

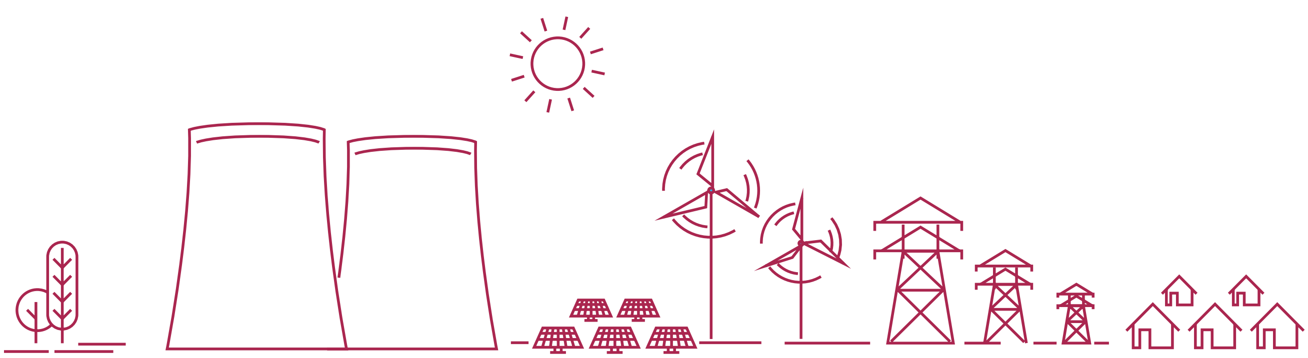
Several sensitivities were analyzed using the internal revenue requirement model including varying levels of energy efficiency, combined cycle size, high renewables, and a phased-in combined cycle build study, which can be found in Appendix M and N. Figure 11.6.2-1 displays the results of the internal revenue requirement analysis of the five energy efficiency sensitivities. Results show that the 2x1 combined cycle in 2022 and 1.50 percent energy efficiency savings program represent the best value for the customer and are also aligned with the Planning Principles.

Figure 11.6.2-1: Reference Scenario Energy Efficiency Sensitivities



SECTION 12

RISK ANALYSIS



12 Risk Analysis

A key objective of the IRP process is selecting a resource plan that will minimize risk in critical areas. DTEE employed some additional approaches besides the scenario and sensitivity analysis already discussed: the analytic hierarchy process (AHP) and a stochastic analysis. In AHP, relevant criteria are selected, ranked, and weighted. DTEE subject matter experts from diverse disciplines applied the criteria and evaluated the results. Criteria included cost, environmental impacts, portfolio balance, and commodity price risk. Stochastic analysis considers various assumptions and resource build scenarios, yielding probabilities of the associated risks. In addition, the 2017 Reference scenario was completed, as well as a change analysis, both of which are supportive of the IRP results.

12.1 Quantified Risk Analysis

DTEE looked at quantifying the risk of 2017 DTEE IRP in two different ways. The first considered analytic hierarchy process (AHP) approach. The second was a stochastic analysis.

12.1.1 ANALYTIC HIERARCHY PROCESS

AHP was developed by Thomas Saaty in the 1970s and has been extensively refined since then. It is 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. The four steps are:

1. State the Objective: Select an IRP resource plan.
2. Define the Criteria: Criteria are then judged against each other using pairwise comparisons.
3. Establish Scenarios and probability of occurrence: The IRP scenarios and a few selected sensitivities will be judged against each other using pairwise comparisons.

4. Develop the Alternative Resource Plans.

5. Synthesize the Information: Determine relative rankings of alternatives over the five scenarios and three relevant sensitivities.

Step 1 State the Objective: Select an IRP resource plan. AHP was used to assess the performance of various resource plans in balancing the DTEE Planning Principles.

Step 2A Define the Criteria. The five criteria selected—cost, environmental impacts, portfolio balance, commodity price risk, and energy risk—were deemed to be important considerations in the IRP process. For each, a metric was developed and extracted from the Strategist modeling results for each resource plan in each scenario. Table 12.1.1-1 shows how the criteria align with the Planning Principles.

Table 12.1.1-1: Energy Risk – 5 Criteria

AHP criteria	Metric	Corresponding IRP Planning Principle
Cost	PVRR	Affordability
Environmental	CO_2 tons	Clean
Portfolio Balance	Function of the amount of Base load to Peaking units added	Flexible and Balanced
Commodity Prices	Weighted average of the Fuel volatility index for gas, coal, nuclear, oil, and renewable	Reasonable risk Flexible and Balanced
Market risk	Net purchases and sales	Reasonable risk

Cost: The cost of each resource plan was determined from the Strategist model on an NPV basis. Included in this cost are: capital cost of new builds, O&M of new builds, fuel of the fleet, and market purchases and sales.

Any differences in costs among the resource plans are captured in this cost number.

Environmental Impacts: CO_2 emission differences among the resource plans were captured over the entire study period. CO_2 was determined to be the dominant environmental consideration over the different portfolios. CO_2 has a price in the High Gas Prices and the Aggressive CO_2 scenarios only. This was captured in the economic results for these scenarios.

Portfolio Balance: This metric was used to capture differences among the types of resources added. Effects of base load versus peaking type units are brought out in this metric. There is approximately 40 percent peaking capacity (peakers, CT, Ludington, and DR) in the DTEE fleet by 2024 in the DTEE 2017 IRP. A more balanced plan for the DTEE system seeks to add base load resources instead of adding to the peaking capacity.

Commodity Price Risk: The fuel required by the portfolio was defined. In trying to achieve favorable fuel diversity, using many different types is preferred, including the free renewable fuel and market purchases. The fleet MBtu mix is weighted by the volatility of the fuels: gas, coal, oil, and market purchases. The daily prices of the fuels from 1999 to 2017 was averaged, and then the standard deviations were calculated. The metric is the (standard deviation/average) weighted average over the fleet MBtu mix. Nuclear volatility was set at zero; renewables and purchases were given a HR of 10,000 MBtu/kwH for this analysis.

Energy Risk: The net purchases and sales over the study period was tracked. Since 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.

Step 2B Judge the Criteria. The ranking of priorities of criteria was done with a pairwise matrix that ranged from 0.11 to 9 according to the scale in Table 12.1.1–2. Each of the five criteria was rated against each other in pairs by DTEE subject matter experts as seen in Table 12.1.13.

Table 12.1.1-2: Rating scale used in AHP pairwise comparisons

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 judgment strongly favor Criteria 1 over Criteria 2

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

Table 12.1.1-3: Judged intensity of importance for criteria

Criteria 1	Criteria 2	Average score
Cost	Environmental	4.17
Cost	Portfolio Balance	5.07
Cost	Commodity Prices	2.45
Cost	Energy Risk	1.48
Environmental	Portfolio Balance	2.35
Environmental	Commodity Prices	1.38
Environmental	Energy Risk	0.63
Portfolio Balance	Commodity Prices	0.54
Portfolio Balance	Energy Risk	0.26
Commodity Prices	Energy Risk	0.43

Step 3 Establish Scenarios and probability of occurrence. The subject matter experts also rated the scenario probability in pairs, using the same rating scale as for the criteria as shown in Tables 12.1.1-4 and 12.1.1-5.

Table 12.1.1-4: AHP Scenario Pairwise Comparison Results

Scenario 1	Scenario 2	Average score
Reference	High Gas	6.90
Reference	Low Gas	3.06
Reference	Emerging Tech.	2.93
Reference	Aggressive CO_2	3.50
High Gas	Low Gas	0.20
High Gas	Emerging Tech.	0.30
High Gas	Aggressive CO_2	0.38
Low Gas	Emerging Tech.	1.62
Low Gas	Aggressive CO_2	1.90
Emerging Technology	Aggressive CO_2	1.86

DTEE evaluated the modeled sensitivities to determine which would affect the base resource plan the most. Three sensitivities were selected for inclusion in the AHP based on their prior results: low load, high load, and high capital costs. These three were also rated against the Reference scenarios. The SMEs for the high load and low load rating were from the DTEE Load Forecasting group. The SMEs for the high capital costs sensitivity were from the DTEE Major Enterprise Projects department.

Table 12.1.1-5 AHP Sensitivity pairwise comparison results

Sensitivity 1	Sensitivity 2	Expert
Reference	High Load	9.0
Reference	Low Load	5.0
High Load	Low Load	0.14
Reference capital costs	High Capital Costs	7.0

A tree with criteria and weightings was developed. See Appendix O for more detail on the development of priority rankings.

Step 4 Develop the Alternative Resource Plans. 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.

After the alternative resource plans were defined, the outputs from the Strategist model runs were extracted from each scenario and sensitivity. The Reference scenario results are shown in Table 12.1.1-7. The results from the other scenarios and sensitivities are shown in Appendix P.

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.

Table 12.1.1-6: Alternative Resource Plans for AHP

Portfolio	Build
Base resource plan	1,100 MW combined cycle in 2022
Wind	950 MW CT in 2022, 1000 MW wind (2017-2023)
Solar	950 MW CT in 2022, 500 MW solar (2017-2023)
Demand Response	950 MW CT in 2022, 150 MW Demand Response (2017-2023)

Table 12.1.1-7: AHP criteria metric results for Reference scenario

	COST (2016-2040 NPV, Billions)	ENVIRONMENTAL (Million tons CO_2 in 2024)	PORTFOLIO BALANCE % peaking capacity[1], % Base load	COMMODITY PRICES (coal, gas, renew, mkt)	ENERGY RISK NET PURCHASES (sales) (GWh)
CCGT	$15.77	28.78	39%, 58%	52%, 13%, 11%, 1%	-113
CT + Wind	$16.24	26.04	47%, 48%	47%, 6%, 19%, 6%	-2488
CT + Solar	$16.17	26.17	47%, 48%	48%, 6%, 13%, 12%	-4603
CT + DR	$15.95	26.23	49%, 49%	48%, 6%, 11%, 13%	-5270

	COST Local Weight	ENVIRONMENTAL Local weight	PORTFOLIO BALANCE Local Weight	COMMODITY PRICES Local weight	ENERGY RISK Local weight
CCGT	0.50	0.07	0.59	0.12	0.52
CT + Wind	0.10	0.33	0.15	0.59	0.25
CT + Solar	0.13	0.31	0.15	0.17	0.13
CT + DR	0.27	0.30	0.12	0.12	0.10

Peaking includes: Peakers, gas CT, Ludington generation, Demand response, Base load includes: coal, gas CC, nuclear, purchases, balance not equalto 100 due to renewables.

Step 5 Synthesize the Information. All the data from the pairwise comparisons and the Strategist output data was input into the AHP Computational Tree calculator.

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. The final scoring also added up to 1.00 and gives the ranking of each alternative. The results are shown in Table 12.1.1-8.

Table 12.1.1-8: The Results of the AHP

Alternative	Score
CCGT	0.402
CT + Wind	0.235
CT + Solar	0.160
CT + DR	0.203

The analytic hierarchy process resulted in the combined cycle portfolio receiving the highest score, thus it is the preferred portfolio across all criteria, scenarios, and sensitivities. Also, the results confirmed that the resource plan containing the combined cycle gas turbine in 2022 provided a favorable balance with respect to the DTEE Planning Principles.

12.1.2 STOCHASTIC ANALYSIS

A stochastic analysis is an advanced modeling technique that uses probability distributions of key drivers to evaluate portfolios. The same portfolios used in the AHP analyses (Table 12.1.1-6) were used in the stochastic analysis. In the analysis, Pace Global utilized the Aurora model to make 200 runs using different draws of the key drivers. Both the average PV of the portfolio cost was determined, as well as the economic risk. The economic risk shows the risk of having a high cost portfolio. It is calculated by taking the average of the highest 10 percent of the draws for each resource plan. The goal is to minimize both the average portfolio cost as well as the economic risk. Key drivers are characterized as probability distribution functions using a combination of historical measures of volatility, market correlations, and the expected future relationships. The modeling evaluated the following with probability distributions: load growth; gas, coal, and oil prices; the price of carbon used for analytic purposes; and the cost of generating technologies. More details are shown in Appendix Q.

Organization of Work

For the stochastic analysis, several steps were undertaken.

- **Task 1: Formulate assumptions.** Starting with the assumption that the 2016 Reference scenario drivers approximated the mean of the applicable probability distribution function for those drivers, Pace Global constructed probability distributions for key drivers, including load growth; gas, coal, and oil prices; the price of carbon used for analytic purposes; and the cost of generating technologies.
- **Task 2: Set up specific MISO Zone 7 portfolio builds.** Because this work was used to look at a specific, firm MISO Zone 7 resource plan in a probabilistic framework, the assumption was that a specific MISO Zone 7 resource (1,100 MW CCGT in 2022) would be treated as a firm resource that remained online regardless of the probabilistic case. These resources were set up as a firm, specific Zone 7 resource that did not change with market and other uncertainties.
- **Task 3: Run Pace Global' s stochastic version of AURORA Model for a joint MISO-PJM Footprint.** Pace Global made runs of its proprietary stochastic version of AURORA for the MISO-PJM footprint, with the resources shown in Table 12.1.2-1 treated as firm resources in each of four cases.

Table 12.1.2-1: Alternative Resource Plans for Stochastic Analysis

Portfolio	Resource Plans
DTEE 2017 IRP	1,100 MW combined cycle in 2022
Wind	950 MW CT in 2022, 1000 MW wind (2017-2023)
Solar	950 MW CT in 2022, 500 MW solar (2017-2023)
Demand Response	950 MW CT in 2022, 150 MW Demand Response (2017-2023)

It is worth noting that the build pattern in Pace Global's stochastic runs reflected two factors:

1. The new resources that are added will be a function of the driving assumptions such as load growth and relative fuel price. Therefore, they differed for each probabilistic case except for the firm resources identified in each of the three cases discussed previously.

2. The build logic used in Pace Global's stochastic model is intended to capture how market players behave in an uncertain world. Therefore, the decision on level, timing, and mix of new resources is determined by the price trajectory seen in prior years. For example, resources added in 2022 will depend on what market players have actually seen in terms of prices (i.e., as projected in the model) for the three years prior to 2022. This logic did not yield a sequence of resource additions that will exactly match those seen when market players make "least cost, perfect foresight" choices in each year.

- **Task 4: Compare the four cases.** The analysis provided output probability distribution functions for key outputs such as electric energy prices.

  Because the analysis is probabilistic, each case can be stated in terms of an expected cost and the standard deviation of that cost or associated risk. This allowed a ranking of the cases in terms of expected cost and risk.

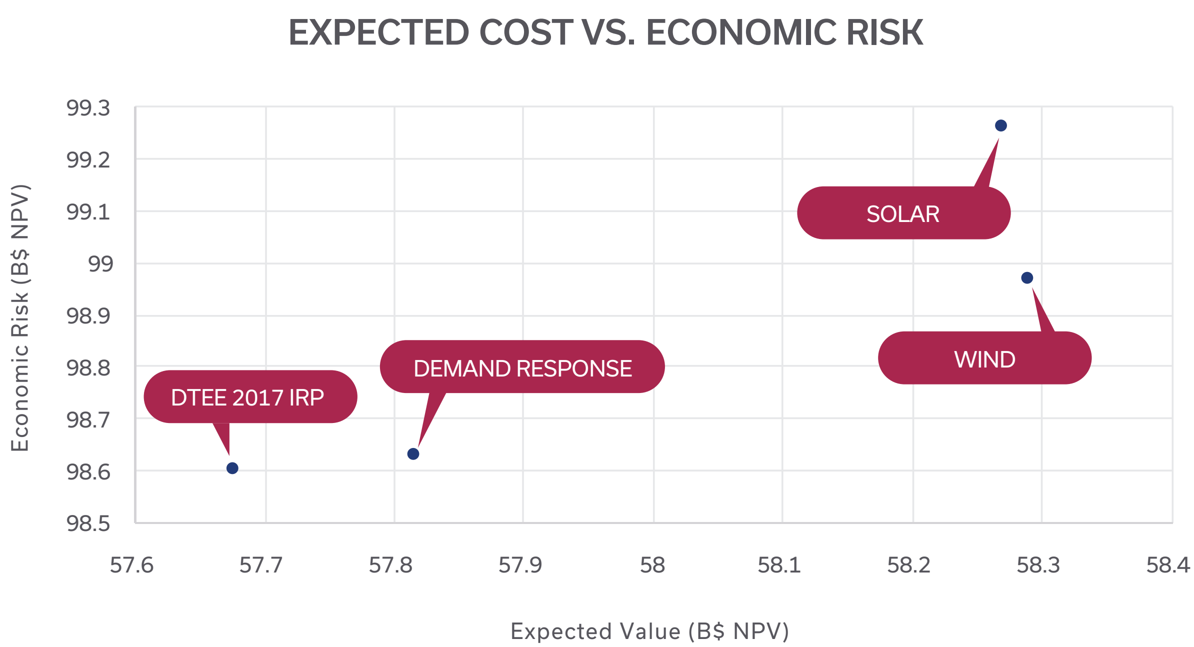
Table 12.1.2-2: Results of the Stochastic Risk Assessment

(000)$ overall portfolio NPV	Expected cost	Economic Risk
DTEE 2017 IRP	57,676,520	98,597,920
Wind	58,289,680	98,966,391
Solar	58,270,378	99,257,940
Demand response	57,816,943	98,628,047

Interpretation of the Results

The DTEE 2017 IRP result to build a combined cycle had the lowest expected cost, defined as the mean portfolio cost over all 200 stochastic draws. This portfolio also had the lowest economic risk, defined as the average of the highest 10 percent of the draws. The goal was to select a portfolio that will minimize both the expected cost and the economic risk. This has been achieved, as seen in Table 12.1.2-2 and Figure 12.1.2-1.

Figure 12.1.2-1: Graph of Expected cost vs. economic risk from the stochastic analysis



12.2 2017 Reference Scenario

As part of the risk analysis, the IRP modeling was completed with the latest assumptions updated in 2017, which confirmed that the recommended portfolio, including a 1,100 MW 2x1 CCGT in 2022, had not changed. This latest scenario is called the 2017 Reference scenario. The following describes the changes from the original Reference scenario to the 2017 Reference scenario.

Loads

Over the forecast period in the 2017 Reference scenario, bundled sales and peak demand are projected to go down slightly by a CAGR of 0.2 percent and 0.1 percent, respectively, in the years 2017 to 2022. Over the entire study period of 2017 to 2040, bundled sales are expected to go down by a CAGR 0.1 percent and peak decreases by 0.2 percent. Figures 12.2-1 and 12.2-2 show the comparison between the Reference scenario and the 2017 Reference scenario loads. Sales, net system output, and peak demand for the 2017 Reference scenario can be found in Appendix R.

Figure 12.2-1 Reference Scenario vs 2017 Reference Scenario (Peak) Forecast (MW)

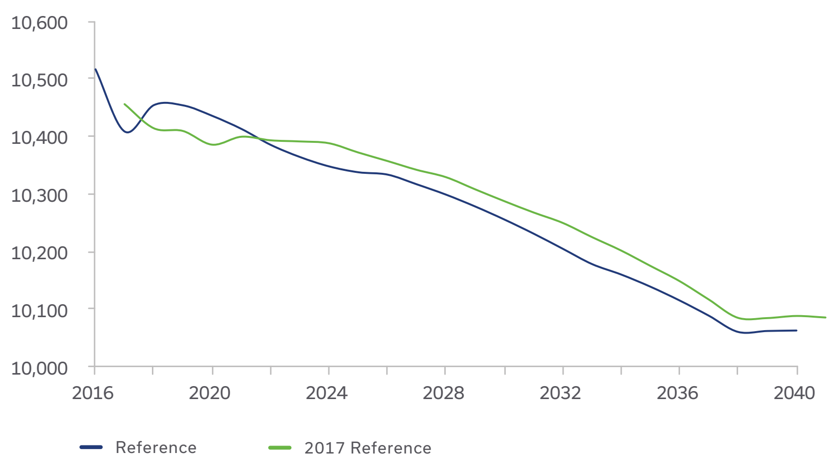
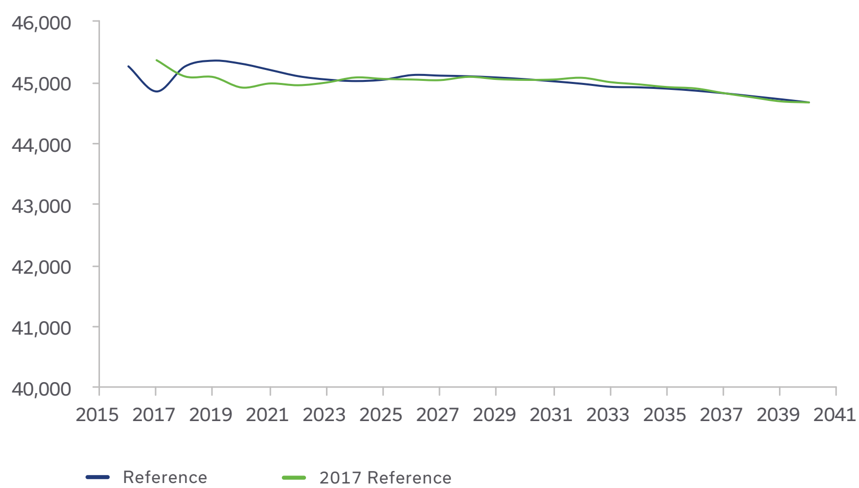


Figure 12.2-2 Reference Scenario vs 2017 Reference Scenario Bundled NSO Forecast (GWh)



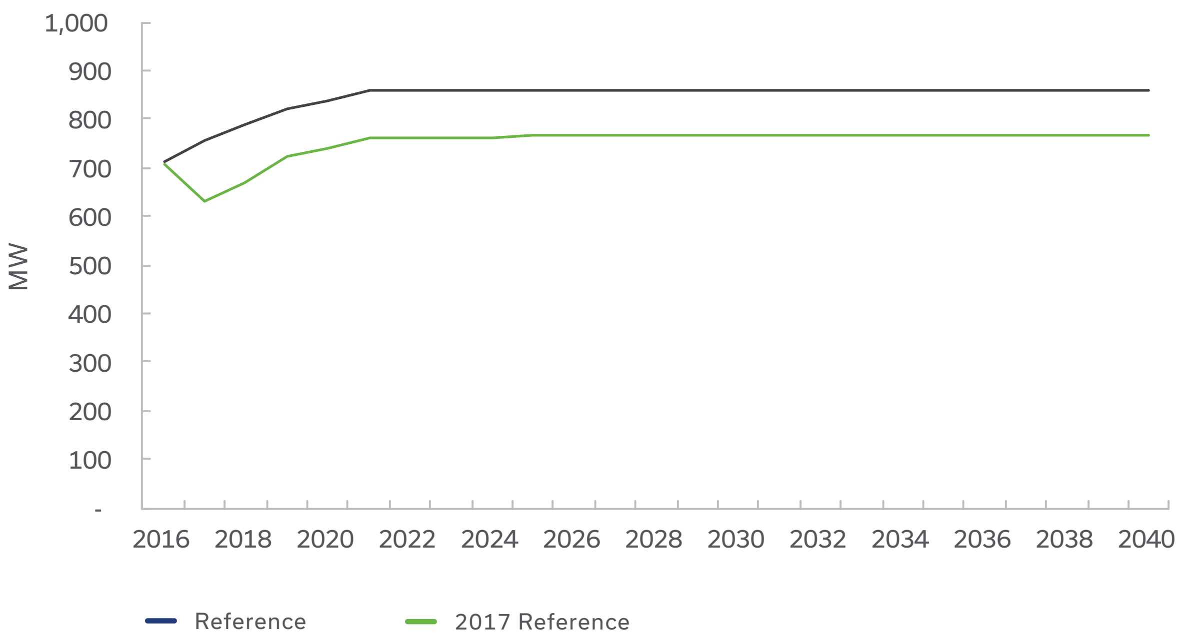
Energy Efficiency

DTEE complied with PA 295 in the Reference scenario. In the 2017 Reference scenario, DTEE has planned for an energy efficiency program that delivers annual energy savings of 1.5 percent through 2021, exceeding the minimum energy savings requirement of 1.0 percent as required by PA 342.

Demand Response

The demand response assumptions from the Reference scenario and the 2017 Reference scenario are shown in Figure 12.2-3. The lowered expectation of DR seen in the graph is attributable to the 2017 Reference scenario having a lower forecasted amount of D8 subscription than the Reference scenario.

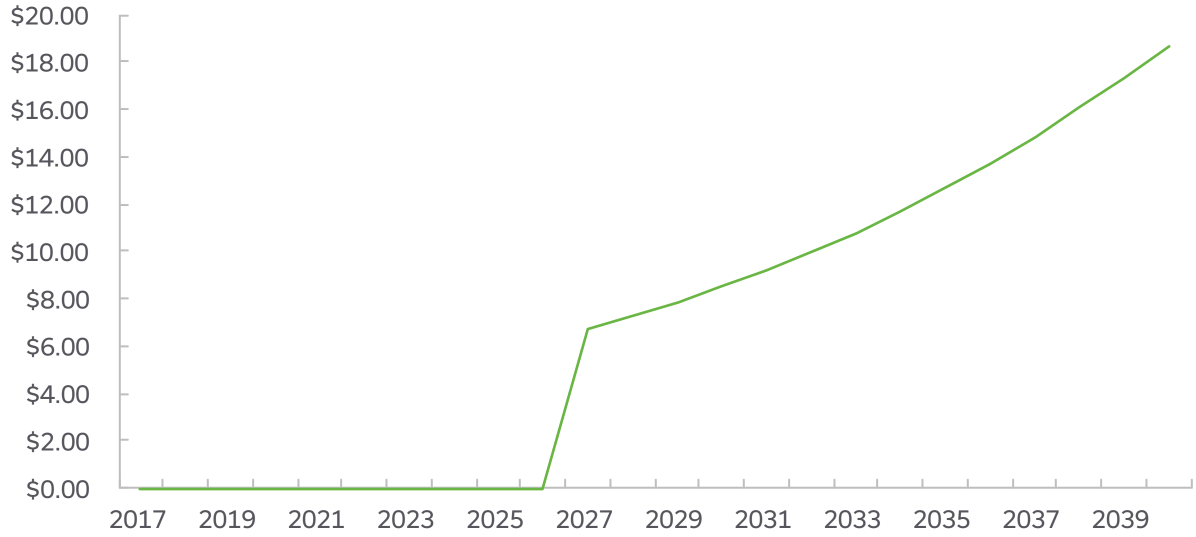
Figure 12.2-3 Demand Response



CO_2 Price

The Reference scenario achieved compliance with the CPP with no CO_2 price; the 2017 Reference scenario has a CO_2 price starting in 2027. In the 2017 Reference scenario, the assumption has changed since the CPP has been put on hold indefinitely. The analysis assumed a nominal carbon price starting in 2027 by pushing the CPP starting year of 2022 out five years to account for program start up time, and new legislation expected to be passed in the early 2020s. The CO_2 price shown in Figure 12.2-4 is assumed to be applied to all technologies and therefore influences the market pricing starting in 2027.

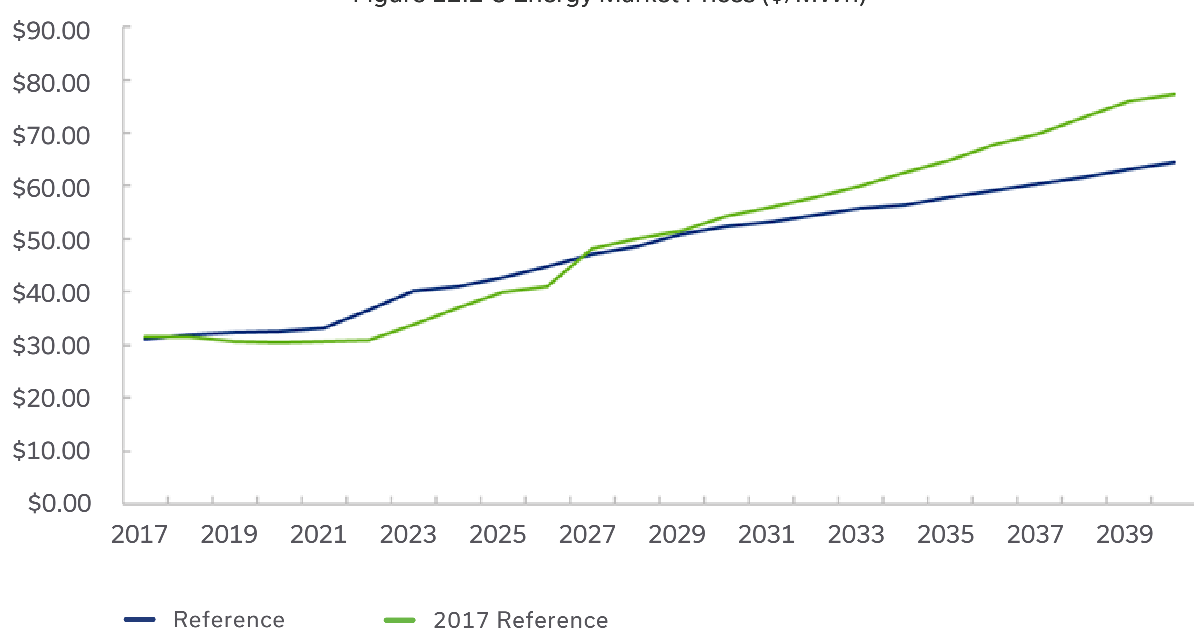
Figure 12.2-4 2017 Reference Scenario CO_2 Prices ($/ton)



Energy Markets

The comparison between the Reference scenario and the 2017 Reference scenario is shown in Figure 12.2-5. The first step change on the 2017 Reference scenario in 2022 is due to the transition from the forwards to the Pace Global forecast in 2022, as described in Section 11.2.6. The second step change is due to the inclusion of a CO_2 price starting in 2027.

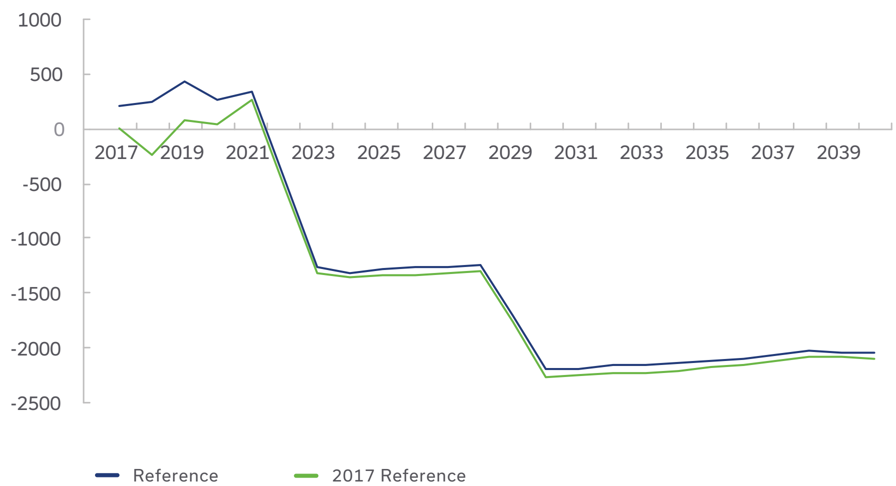
Figure 12.2-5 Energy Market Prices ($/MWh)



Shortfall

The 2017 Reference scenario and the Reference scenario shortfalls are shown in Figure 12.2-6. Differences include updated UCAPs on the units, which account for much of the variance in 2017 to 2021. See Appendix S for more detail.

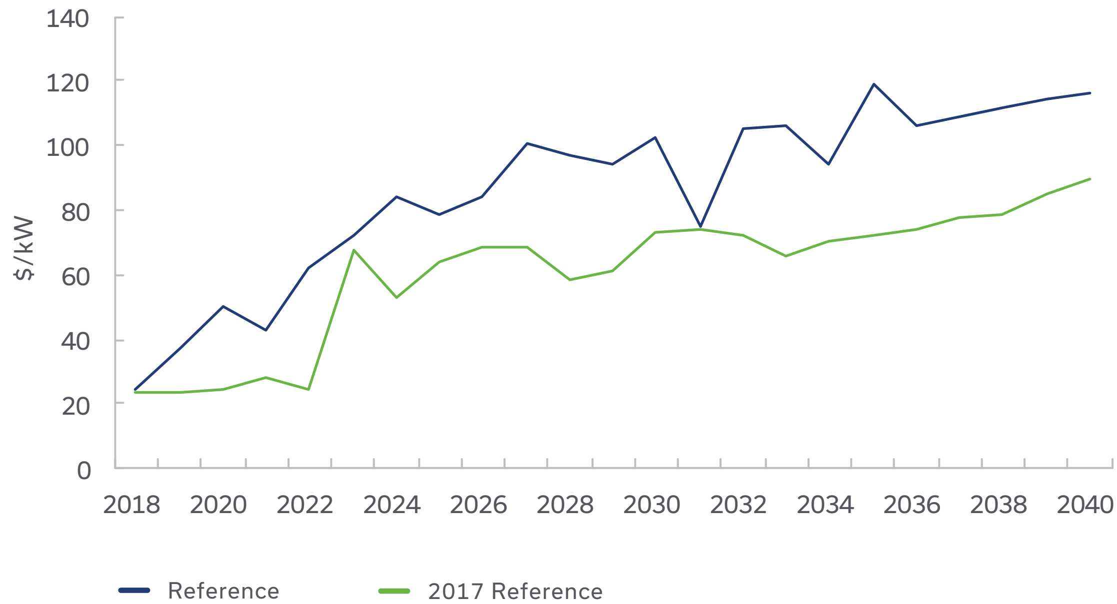
Figure 12.2-6: Shortfall (MW)



Capacity Price

The 2017 Reference scenario capacity price forecast as shown in Figure 12.2-7 is lower than the Reference scenario due to updated assumptions.

Figure 12.2-7: Capacity Price forecast ($/kW)



Combined Cycle Gas Turbine Assumptions

In the Reference scenario modeling, the generic CCGT was assumed. Since that time, the inputs for the CCGT have been updated, based on updated information, as shown in Table 12.2-1.

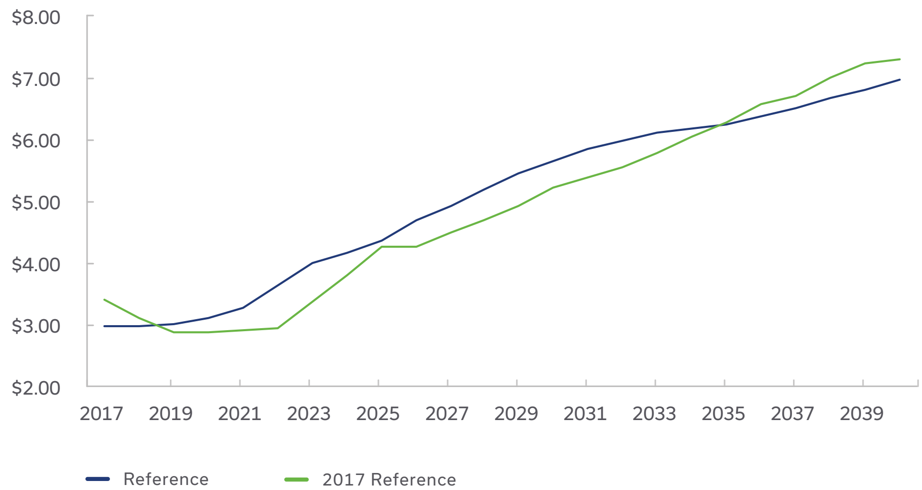
Table 12.2-1: CCGT Assumptions

	Generic Combined Cycle Assumptions	2017 Combined Cycle Assumptions
Size (MW)	959	1076
Duct firing (MW)	100	72
Heat Rate (Btu/kWh)	6348	6250
Cost ($/kW)	$1055	$924

Gas Price

Figure 12.2-8 shows the gas price forecasts for the two scenarios. There is a one-year forwards to the Pace Global forecast transition in 2022 for the Reference scenario, and a two-year transition in 2023 and 2024 for the 2017 Reference scenario. Other inputs for the 2017 Reference case including fuel prices are shown in Appendix T.

12.2-8 Gas Price Forecast ($/MBTu)



Renewables

In December of 2016, the Michigan Legislature enacted PA 342, which amended PA 295 of 2008 and outlines updated requirements for renewable energy in Michigan. Under the new law, the renewable energy credit portfolio shall consist of 10 percent renewable energy credits, as required under former section 27 of 2008 PA 295 through 2018. In 2019 and 2020, a renewable energy credit portfolio shall consist of at least 12.5 percent, and in 2021, at least 15 percent. The 2017 Reference scenario reflects the Company's approach to ensure compliance with PA 342.

Table 12.2-2: Renewables assumptions

WIND, MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Reference scenario	50		150		100				100		**500**
2017 Reference scenario			161		150	225	**150**				**686**

SOLAR, MW	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	Total
Reference scenario	50		15	15	20						**100**
2017 Reference scenario		50		5	5						**60**

Strategist Results

Two sensitivities were run in the Strategist model: the 2017 Reference base and the 75% CO_2 Reduction by 2040. In the Reference scenario base, the resource plan selected, as shown in Table 12.2-3, is the economical and prudent resource plan to add CCGTs in 2022 and in 2029. For the 75% CO_2 reduction by 2040 sensitivity, the retirement plan was modified and CO_2 emission constraints were used in the Strategist modeling. More renewables were selected along with CCGTs in 2022, 2029, and 2039.

In the 75% CO_2 reduction by 2040 sensitivity, the Monroe coal unit retirements were moved earlier. Monroe Units 1 and 2 would be retired in 2039, and Monroe Units 3 and 4 would be retired in 2040.

Table 12.2-3: 2017 Reference Scenario Build Plans

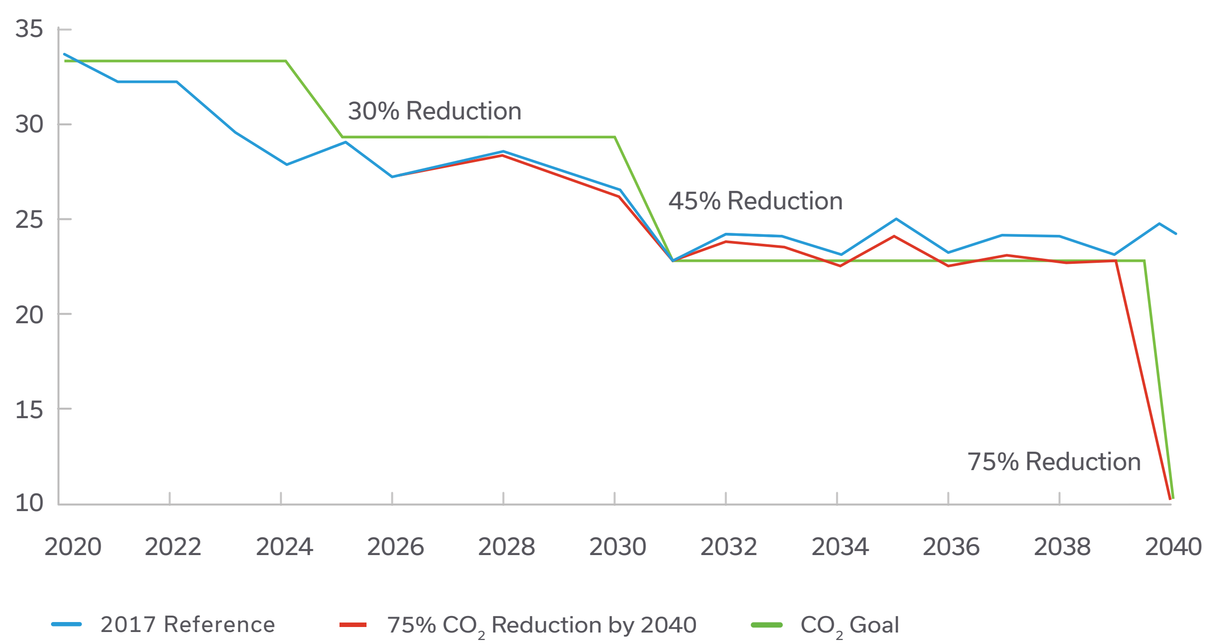
	2017 Reference Base	75% CO_2 Reduction by 2040
2016	IACB (1) EE 1.5%	IACB (1) EE 1.5%
2017		
2018	PUR (245)	PUR (245)
2019		
2020		
2021		
2022	NEW CC (1)	NEW CC (1)
2023	PUR (226)	PUR (226)
2024	PUR (264)	PUR (264)
2025	PUR (257)	PUR (216) S (50), W (100)
2026	PUR (251)	PUR (173) S (75)
2027	PUR (235)	PUR (107) S (100)
2028	PUR (225)	(PUR 31) S (100), W (100)
2029	NEW CC (1)	S (100), NEW CC (1)
2030	PUR (107)	S (200)
2031	PUR (102)	S (200), W (100)
2032	PUR (83)	S (200)
2033	PUR (78)	S (200)

2034	PUR (54)	S (200), W (100)
2035	PUR (26)	S (200)
2036		S (200)
2037		S (200), W (100)
2038		S (200)
2039		S (200), NEW CC (1)
2040		PUR (296) S (200)

75% CO_2 reduction by 2040

The 75% CO_2 reduction by 2040 sensitivity meets the Company's announced aspiration, by reducing CO_2 emissions, as shown in Figure 12.2-9.

Figure 12.2-9: CO_2 Emissions (Million tons)



12.3 Change Analysis

Scenarios and sensitivities were analyzed to measure how much the resource plan would change if certain unknowns in the future came to pass. The 2x1 CCGT was the selected build in the High Gas Prices scenario, the high renewables sensitivities, and the high capital sensitivity. A different resource plan in 2022 resulted from the sensitivities shown in Table 12.3-1.

Table 12.3-1: Change Analysis

Sensitivity	Build Plan change	Mitigation
High Load Sensitivity	3X1 instead of 2X1	Obtain more resources once certain
Low Load Sensitivity	2X1 in 2023 instead of 2022	Delay CCGT once certain
Commercial Choice Returns	3X1 instead of 2X1	Obtain more resources once certain
Commercial and Industrial Choice returns	Market purchases in 2020-2021; extra 3X1 in 2023 (in addition to the 2X1 in 2022)	Obtain more resources once certain
2 % Energy Efficiency	2X1 in 2023 instead of 2022	Delay CCGT once certain

Two themes emerge from Table 12.3-1. In the high load and both choice return cases, additional resources will be needed, and CCGT technology was still selected. In the low load and the 2.0 percent EE sensitivities, the CCGT technology was still selected; however, it is delayed one year. If future signposts indicate than the load is higher than forecasted or choice load is known to be returning, issuing a RFP for added capacity to bridge until the next IRP is completed would mitigate this situation. Similarly, if sales are lower than forecasted, economic analysis could be done to determine the value of delaying the proposed project by one year. The value of the delay would be offset by the risk of some of the remaining coal units needing to retire earlier than 2023.

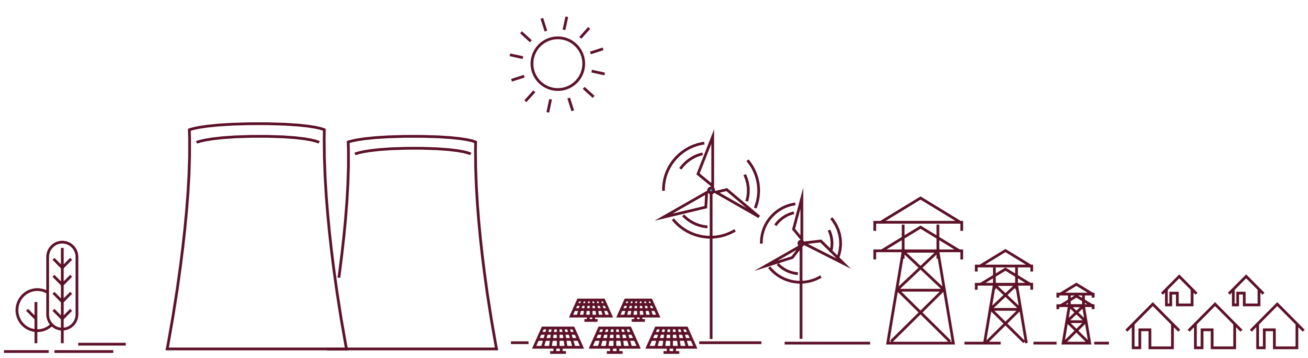
12.4 Conclusions of the Risk Analysis

The conclusions of the four types of risk analysis performed indisputably supported the selection of the 2x1 CCGT in 2022 over other alternatives. In the AHP risk analysis, the CCGT portfolio was selected over the wind/CT, solar/CT, and DR/CT portfolios by a dominant margin. The expected cost and the economic risk of the 2022 CCGT portfolio were the lowest of the four portfolios considered in the stochastic analysis. The 2017 Reference scenario was run with the latest assumptions and inputs to the IRP models. The 2x1 CCGT in 2022 was selected in the 2017 Reference base and in the 2017 Reference 75% CO_2 reduction by 2040 sensitivity. In the 75% CO_2 reduction by 2040 sensitivity, the DTEE fleet reduces CO_2 by 75 percent in 2040 by adding a significant renewable build to the fleet and by selecting three 2x1 CCGTs by 2040. The first CCGT added in

2022 was shown to be an important first step in the recently announced low CO_2 aspirational strategy for DTEE. Finally, in the change analysis, five sensitivities that did not select a 2x1 CCGT in 2022 were analyzed for adaptability with the 2022 2x1 CCGT that was present in a preponderance of the other sensitivities. Results showed that more resources could be added in concert with the 2022 2x1 CCGT, or the 2022 addition could be pushed out by one year, without negatively affecting the preference for the first 2x1 CCGT addition.

SECTION 13

PROPOSED COURSE OF ACTION

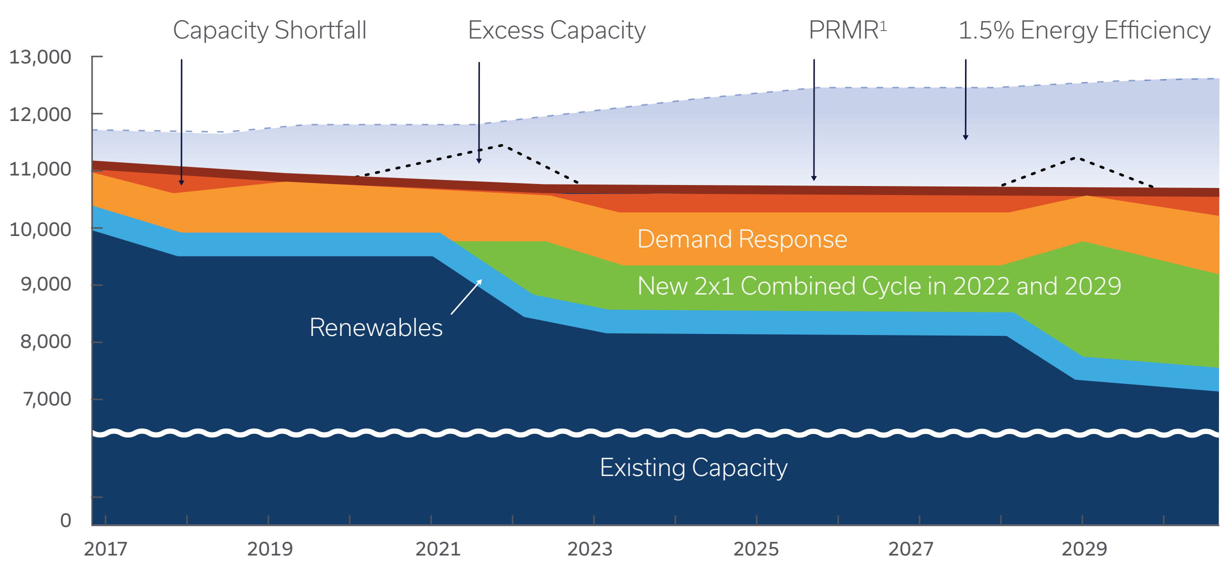


13 Proposed Course of Action

The IRP process resulted in the DTEE 2017 IRP, including an 1,100 MW CCGT in 2022 and potentially again in 2029, in addition to planned additions of renewables, EE, and DR, to address the additional capacity need projected to begin in 2022.

Figure 13-1 shows the resources added and potential unit retirements for the period 2017-2030. The short-term implementation plan identifies actions DTEE will take from 2017 through 2021 to implement the DTEE 2017 IRP.

Figure 13-1: DTEE 2017 IRP (MW)



Note 1: Planning Reserve Margin Requirement

13.1 Integrated Resource Planning Summary

DTEE's integrated resource planning process is helping to guide energy resource decisions, which are necessary to meet future demand for electricity. DTEE relies on the Planning Principles—reliability, affordability, clean, flexible and balance, compliant, and reasonable risk—to maintain a long-term resource plan that will assist in providing safe, reliable, and affordable electricity to DTEE's customers in a constantly changing business and regulatory environment.

DTEE used an integrated, cost-based system planning process that accounts for electricity demand, reliability, costs, resource diversity, risk mitigation, environmental issues, and the performance variation inherent to individual energy resources. The IRP analysis relied on the Strategist model from ABB and incorporated best practices. The resource cost and performance input data was provided by HDR and DTEE subject matter experts; the modeling inputs and process were corroborated by ABB.

Various scenarios and sensitivities were utilized so that major drivers such as commodity prices, energy demand, and environmental regulations were evaluated to provide robustness to the DTEE 2017 IRP. Constraints, including reliability, regulatory, and corporate and environmental objectives, were considered in various combinations of strategies and predictions of future conditions, all of which were analyzed and evaluated.

13.2 Integrated Resource Plan

DTEE evaluated numerous resource options to determine the recommended combination of supply-side, demand-side, self-build, and market resources to meet its capacity needs. DTEE performed scenario and sensitivity analyses to test the robustness of the DTEE 2017 IRP given the uncertainty around environmental regulations, resource cost and performance, fuel prices, load, and other regulatory/legislative effects. The IRP process identified that significant additional capacity will be needed beginning in 2022 to cover reserve margin requirements, predominantly as a result of the projected retirements of River Rouge, St. Clair, and Trenton Channel power plants from 2020 to 2023. DTEE anticipates the need for an 1,100 MW CCGT in 2022 and potentially again in 2029, in addition to planned additions of renewables, EE, and DR, to address the additional capacity need projected to begin in 2022. Table 13.2-1 shows the resources added and the potential unit retirements for the period 2017-2040. The DTEE 2017 IRP reflects increased energy efficiency and demand response resources, increased renewable generation, and market purchases.

Table 13.2-1: DTEE 2017 IRP

DTEE 2017 IRP				
Category	Project	Description	MW[1] Impact	Years of implementation
Energy Efficiency Resources		Expand Program in harmony with PA 342	1.5% Sales annually	2018-2030
Demand Response Resources	Interruptible Air Conditioning	Incremental increase from 2017	125 MW[2]	2018 to 2023
Renewables	Solar Wind	Expand Renewable Portfolio to meet PA 342	30 MW[3] 107 MW[3]	2017-2025
Generic CHP	New Project	Possible CHP installation	35MW	2020
Fossil Unit Retirements	River Rouge 3 St. Clair 1-4, 6 & 7 Trenton 9 Peakers Belle River 1 & 2		-234 MW -1215 MW -430 MW -17 MW -998 MW	2020 2022, 2023 2023 2020-2023 2029-2030
Replacement CCGT	Proposed project	Addition of 2x1 Combined Cycle	1067 MW 1067 MW	2022 2029
Pumped Storage Upgrades	Ludington 1-6	Efficiency increase and capacity improvement of pumped storage	227 MW	2017-2020
Market Purchases		Used to balance short term capacity position	up to 300 MW	2022-2040

1. Impact is UCAP (i.e. MISO capacity credit)
2. 135 MW adjusted for PRMR and Transmission Losses
3. Nameplate for solar is 60 MW and wind is 686 MW

DTEE has determined through its IRP process the types of resources that would need to be acquired to prudently serve customers during the 24-year study period. DTEE will seek regulatory approval to bring new resources into its portfolio as appropriate. The IRP process is part of DTEE's ongoing business process, and new information will be integrated as it becomes available.

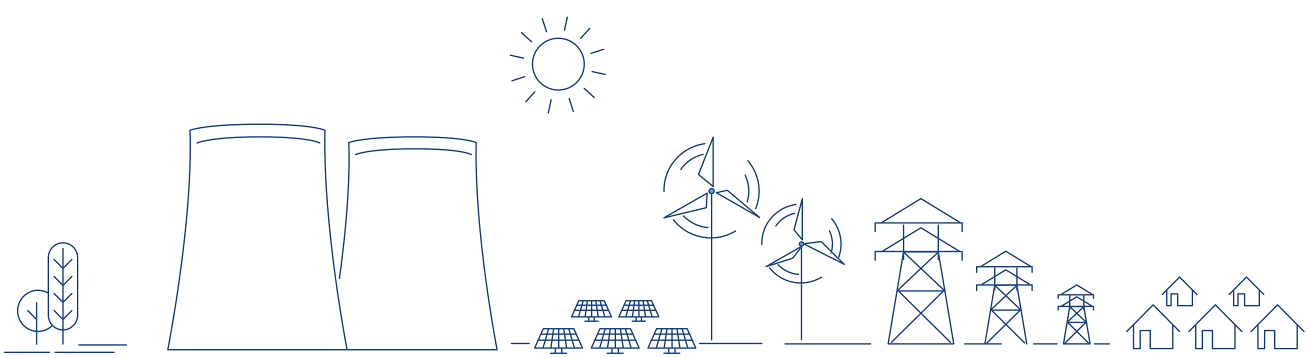
13.3 Short-Term Implementation Plan

This Short-Term Implementation Plan identifies the steps that DTEE will take from 2017 through 2021 to implement the DTEE 2017 IRP. In these years, DTEE will supplement its capacity needs through the MISO Capacity Auction or bi-lateral contracts and demand response resources. DTEE will also continue to:

- Expand renewable generation portfolio to meet the requirements of Act No. 342 Public Acts of 2016
- Continue the EO program in harmony with the requirements of Act No. 342 Public Acts of 2016
- Offer service options for customers, including EO and voluntary renewable energy programs
- Maintain its industry-leading position in the utilization of demand response resources
- Keep generation plants running safely, reliably, and cost effectively until scheduled retirements
- Complete Ludington expansion
- Seek approvals as appropriate to implement its plan, including the CON filing to add a combined cycle

DTEE will continue to evaluate changes in load, energy/commodity markets, regulatory rules, legislative requirements, environmental impacts, and technologies that may affect the plan.

GLOSSARY



The following definitions are not intended to set forth official Company policy or interpretation, but are provided solely to assist the reader in the understanding of this report.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC):

The net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when used.

AVAILABILITY:

The percentage of time that a unit is available to generate electricity. It is determined by dividing the total hours the unit is available to generate by the total hours in the period.

BASE RESOURCE PLAN:

A set of resources throughout the 2016 to 2040 study period that stay consistent under each scenario to be used to compare sensitivities against. The Base Resource Plan should be used to gauge whether a sensitivity is more cost effective or not.

CAPACITY FACTOR:

A measure of how much a generating facility's capacity is used during a period. Expressed as a percentage, it is calculated by dividing the actual energy produced during a specific period by the unit's rated generating capacity over the same period.

% Capacity Factor = (energy produced) / (plant capacity x time)

COGENERATION:

The generation of electric power and one or more other useful energy products, such as steam or hot water.

COMBINED CYCLE:

A generating unit that utilizes a combination of one or more combustion turbines in conjunction with heat recovery steam generator(s) (HRSG) and steam turbine(s).

CONSUMER PRICE INDEX (CPI):

A relative measure of the purchasing power of a dollar. It is a measure of inflation.

DEMAND:

The energy required at the customer's meter.

DEMAND-SIDE MANAGEMENT (DSM):

Programs designed to influence customer use of electricity in ways that will produce desired changes in a utility's load shape. The proposed programs support the objectives of conservation, load shifting, and peak clipping.

DEMAND-SIDE OPTION (DSO):

A resource option which meets the objectives stated for a DSM program (see previous definition).

DISPATCHING:

The assignment of load to specific generating units and other sources to effect the most reliable and economical supply as system load rises or falls.

DISTRIBUTED GENERATION:

Small-scale electric generating facilities located at sites throughout the utility's service area. Dispersed generation is a form of distributed generation.

DTEE 2017 IRP:

A set of resources within the 2016 to 2040 study period that is the result of scenario and sensitivity analysis, and risk analysis and encompasses the DTEE's Planning Principles that represents DTEE's proposed course of action.

HEAT RATE:

A measure of generating plant efficiency in converting the heat content of its fuel to electrical energy, expressed in BTU/kWh. It is computed by dividing the total BTU content of fuel burned for electric generation by the resulting net kilowatt-hour generation.

HEAT RECOVERY STEAM GENERATOR (HRSG):

A boiler designed to produce steam by using rejected heat, such as that from exhaust of a combustion turbine.

INTEGRATED COAL GASIFICATION COMBINED CYCLE (IGCC):

A combined cycle plant, along with the gasification equipment used to produce synthetic gas from coal.

LEVELIZATION:

A mathematical operation whereby a non-uniform series of annual payments is converted into an equivalent uniform series considering the time value of money (discount rate).

LOAD FACTOR:

The ratio of the average load supplied during a designated period to the peak or maximum load occurring in that period. It is expressed as a percent.

LOSS OF LOAD EXPECTATION (LOLE):

The frequency that there will be insufficient resources (native generation and purchases) to serve firm load. DTEE's reliability criterion is one day in ten years loss of load expectation.

PLANNING PERIOD:

The time during which resource options are added to meet the expected future electrical loads. For this IRP, the planning period is 2016-2040.

PROVIEW:

The Strategist automatic expansion planning module, which determines the optimum expansion plan under a prescribed set of constraints and assumptions.

PUMPED STORAGE:

The process of producing electricity during peak periods with water driven turbines. The water storage reservoir is filled by motor driven pumps during off-peak hours when inexpensive power is available.

RENEWABLES:

An energy source that occurs naturally in the environment, such as solar energy, wind currents, and water flow.

RESERVE MARGIN:

The difference between net system capability and system maximum load requirement (peak load). It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads. This is often expressed as a percentage of peak load.

Reserve margin = 100 x (Total System Capacity – Peak Load) / Peak Load

RESOURCE PLAN:

A strategy for meeting the expected future electrical demand through the addition of supply-side and/or demand-side options. For this IRP, resource plans were developed for several different scenarios and sensitivities.

REVENUE REQUIREMENT:

The revenue that must be obtained to cover all annual costs, including all fixed and variable cost components.

SCENARIO:

A unique set of assumptions grouped to best represent the effect of some potential future occurrence.

SELECTED RESOURCE PLAN:

A set of resources within the 2016 to 2040 study period that aligns with the Company's Planning Principles and selected as the optimal resource plan under a specific scenario.

SENSITIVITY:

A subset of a scenario in which the same basic assumptions are used as in the controlling scenario, but certain other parameters are modified to determine specific effects that might occur.

SUPPLY-SIDE OPTION (SSO):

Typically, any option which adds generating capacity to a system to produce electricity as needed to meet customer electrical demand.

TIME OF USE RATES:

Tariffs that vary according to the time of day. They are used to help promote transfer of on-peak to off-peak electricity consumption.

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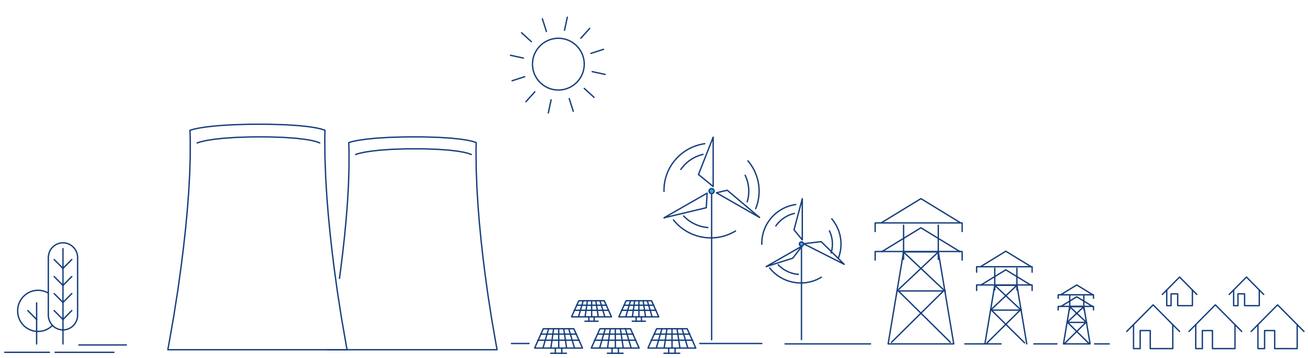
OF ABBREVIATIONS



ACI — activated carbon injection

ADMS— Advanced Distribution Management System

AFUDC— allowance for funds used during construction

AHP — analytic hierarchy process

ASHRAE — American Society of Heating, Refrigerating and Air-Conditioning Engineers

BR— Belle River Power Plant

CAA— Clean Air Act

CAGR — compound annual growth rate

CAIR— Clean Air Interstate Rule

CC, CCGT— combined cycle gas turbine

CF— capacity factor

CHP— combined heat and power

CME — Chicago Mercantile Exchange

CPP— Clean Power Plan

CO_2— carbon dioxide

COG — coke oven gas

CSAPR— Cross-State Air Pollution Rule

CT— combustion turbine

CWA— Clean Water Act

DER— distributed energy resources

DG— distributed generation

DR— demand response

DSI— dry sorbent injection

DSM— demand-side management

DTE — DTE Energy Company

DTEE — DTE Electric Company or The Company

EE — energy efficiency

EIA — Energy Information Agency

ELG — Effluent Limitation Guidelines

EM&R— Environmental Management & Resources business unit

EO — energy optimization

EPA — Environmental Protection Agency

EPC — engineering, procurement, and construction

EPRI — Electric Power Research Institute

ESS — energy storage systems

ESP — electrostatic precipitator

FERC — Federal Energy Regulatory Commission

FGD — flue gas desulfurization

FOM — fixed operating and maintenance

FosGen — Fossil Generation business unit

FRAP — fixed resource adequacy plan

GDS — GDS Associates, Inc.

GenOps — Generation Optimization business unit

GIA— Generator Interconnection Agreement

GW — gigawatt, one billion watts

GWh — gigawatt hours

HAP — hazardous air pollutant

HDR — HDR, Incorporated (engineering firm)

HELM — Hourly Electric Load Model

HRSG — heat recovery steam generator

HSE — high-sulfur eastern coal

HVAC — heating, ventilation and air conditioning

ICAP — installed capacity

IGCC — integrated gasification combined cycle

IMM — Independent Market Monitor

IPP — Independent Power Producer

IRP — Integrated Resource Plan

ITC — International Transmission Company

ITC — Investment Tax Credit

kW — kilowatt, one thousand watts

kWh — kilowatt hours

LCOE — levelized cost of electricity

LED — light emitting diode

LEED — Leadership in Energy and Environmental Design

LF — load factor

LCR — Local Clearing Requirement

LMP — Local Marginal Price

LOLE — loss of load expectation

LSS — low-sulfur southern coal

LSW — low-sulfur western coal

MACT — maximum achievable control technology

MATS— Mercury and Air Toxics Standards

MAPE — mean absolute percentage error

MBtu, mmBtu — million British Thermal Units

MDEQ — Michigan Department of Environmental Quality

MEP M — Major Enterprise Projects business unit

MISO — Mid-Continental Independent Transmission System Operator, Inc.

MN — Monroe Power Plant

MPPA— Michigan Public Power Agency

MPSC— Michigan Public Service Commission

MSE — mid-sulfur eastern coal

MTEP — MISO Transmission Expansion Plan

MW — megawatt, one million watts

MWh — megawatt hours

NAAQS — National Ambient Air Quality Standards

NITS — network integration transmission service

NMP — non-metal processing

NO_x — nitrogen oxide

NPV — net present value

NPVRR — net present value revenue requirement

NYMEX — New York Mercantile Exchange

O&M — operating and maintenance

OASIS — Open Access Same-Time Information System

OFA — over-fire air

PA — Public Act

Pace Global — Pace Global, a Siemens business

PMBC — Pure Michigan Business Connect

PPA — power purchase agreement

PRMR — Planning Reserve Margin Requirement

PSCR — Power Supply Cost Recovery

PTC — point-to-point transmission service

PTC — Production Tax Credit

PURPA — Public Utility Regulatory Policies Act

QF — qualifying facility

R-10 — Rider 10 industrial interruptible tariff

RCRA — Resource Conservation and Recovery Act

RCx — Retro Commissioning

REC — Renewable Energy Credit

RFP — request for proposal

RGGI — Regional Greenhouse Gas Initiative

RIM — Ratepayer Impact Measure test

R&MP — rubber and plastics

ROR — random outage rate

RR — River Rouge Power Plant

SC — St. Clair Power Plant

SCR — selective catalytic reduction

SIP — State Implementation Plan

SO2 — sulfur dioxide

TC — Trenton Channel Power Plant

UCAP — unforced capacity

UCT — Utility Cost Test

VOC — volatile organic carbons

VOM — variable operating and maintenance (cost)