requesting CONs for the construction of a 1,100 megawatt (MW) natural gas combined cycle (NGCC) electric generation facility at the company's Belle River Power Plant site. Specifically, DTE Electric seeks CONs that: (1) the power to be supplied by the proposed project is needed; (2) the size, fuel type, and other design characteristics of the proposed project represent the most reasonable and prudent means of meeting that power need; and (3) the estimated $989 million capital costs of, and the financing plan for, the proposed project will be recoverable in rates from DTE Electric's customers.

On September 7, 2017, a prehearing conference was held before Administrative Law Judge Suzanne D. Sonneborn (ALJ). At the prehearing conference, the ALJ granted intervention to the Michigan Department of the Attorney General (Attorney General); the Association of Businesses Advocating Tariff Equity (ABATE); City of Ann Arbor (Ann Arbor); Energy Michigan; International Transmission Company (ITC); Midland Cogeneration Venture Limited Partnership (MCV); Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (together, MEC/NRDC/SC); Ecology Center, Solar Energy Industries Association, Union of Concerned Scientists, Vote Solar, and Environmental Law & Policy Center, (collectively, ELPC *et al.*); and the Michigan Energy Innovation Business Council (EIBC). The Commission Staff (Staff) also participated in the proceeding.

On September 7, 2017, ABATE, MEC/NRDC/SC, the Attorney General, and the MCV (Movants) filed a joint motion to compel discovery of DTE Electric's ABB Strategist and ABB PROMOD computer models and associated workpapers or, alternatively requested that the ALJ grant their joint motion in limine to exclude all testimony and exhibits that rely on the modeling or related workpapers. On October 2, 2017, the Staff and ELPC *et al.* filed responses in support of the motions, and DTE Electric filed a response opposing the motions along with a cross-motion requesting a protective order. On October 5, 2017, the ALJ conducted a hearing on the motions, and on October 10, 2017, she issued a ruling (October 10 ruling) granting Movants' joint motion to compel and denying the joint motion in limine. The ALJ held in abeyance DTE Electric's cross-motion for a protective order pending modifications of that order to comport with the remainder of her ruling.

On October 18, 2017, Movants filed a joint motion to clarify or enforce the ALJ's October 10 ruling, and a motion to modify the schedule. Alternatively, Movants renewed their joint motion in limine to exclude portions of DTE Electric's testimony and exhibits. On October 23, 2017, DTE Electric filed a response opposing the joint motions. The ALJ conducted a hearing on the motions on October 24, 2017, and she granted the joint motion to enforce the October 10 ruling. On October 30, 2017, the ALJ entered a protective order.

On December 1, 2017, the Staff moved to extend the schedule beyond the 270-day statutory deadline. On December 4, 2017, DTE Electric filed a motion to limit discovery of engineering, procurement, and construction (EPC) bids. On December 7, 2017, MEC/NRDC/SC filed a response supporting the Staff's motion to extend the schedule. On that same date, DTE Electric filed a response opposing the Staff's motion, and ABATE filed a response in support of the Staff's motion and opposing DTE Electric's motion. The Staff also filed a response opposing DTE Electric's motion.

On December 11, 2017, the ALJ held a hearing on DTE Electric's and the Staff's motions, and on December 12, 2017, the ALJ issued a ruling granting the requested extension. DTE Electric appealed the ruling, and on January 23, 2018, the Commission issued an order reversing the ALJ and finding that, to meet the statutory deadline, the Commission would read the record.[1]

On February 7, 2018, the Staff, the Attorney General, and ABATE filed motions to strike, all or in part, certain rebuttal testimony and exhibits filed by DTE Electric witnesses. On February 9, 2018, DTE Electric filed responses opposing the motions. The ALJ denied ABATE's motion to strike and granted the Staff's and Attorney General's motions. 5 Tr 1407-1409, 1418-1425.

Evidentiary hearings were held on February 14-16, 2018. On February 22, 2018, DTE Electric filed a request for corrections to the transcript, which was unopposed and which the ALJ granted on March 1, 2018. DTE Electric, the Staff, the Attorney General, ABATE, MEC/NRDC/SC, ELPC *et al.* and EIBC filed initial briefs on March 2, 2018. On March 12, 2018, DTE Electric, the Staff, ABATE, MEC/NRDC/SC, ELPC *et al.*, and Ann Arbor filed reply briefs. The record in this proceeding consists of 2,617 pages of transcript and 471 exhibits admitted into evidence. All or part of several exhibits and portions of the transcript were filed under seal and are not available in the public record.

[1] The Commission seeks to clarify that it agrees with the ALJ's legal conclusion in her December 12 ruling regarding the statutory deadline under applicable law. As a matter of policy, however, the Commission has prioritized the timely issuance of orders to comply with statutory directives and provide regulatory certainty. The Commission recognizes that exceptional circumstances may present themselves making it impossible or inappropriate to meet statutory deadlines in certain cases, even with the Commission doing all it can to expedite the process. While the Commission did not find compelling circumstances to grant an extension in this proceeding and was able to comply with the 270-day deadline by reading the record, the Commission is disturbed by DTE Electric's discovery tactics and interference with other parties' abilities to obtain data germane to the issues in this proceeding in a timely manner. As outlined in its guidance for upcoming integrated resource plan (IRP) proceedings under section 6t, the Commission stresses the importance of engaging with technical stakeholders to provide transparency around modeling approaches, assumptions, and data sources and to freely exchange underlying modeling data for analysis by parties. While the Commission expects a more cooperative approach in the future, it would not rule out sanctions for discovery abuses as provided under MCR 2.313 and Mich Admin Code, R 792.10423.

II. LEGAL STANDARDS

As explained previously, DTE Electric requested three CONs under MCL 460.6s(3)(a), (b), and (d). MCL 460.6s provides:

> (1) An electric utility that proposes to construct an electric generation facility . . . may submit an application to the commission seeking a certificate of necessity for that construction . . . if that construction . . . costs $100,000,000.00 or more and a portion of the costs would be allocable to retail customers in this state.
>
> * * *
>
> (3) An electric utility submitting an application under this section may request 1 or more of the following:
>
> (a) A certificate of necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed.
>
> (b) A certificate of necessity that the size, fuel type, and other design characteristics of the existing or proposed electric generation facility . . . represent the most reasonable and prudent means of meeting that power need.
>
> * * *
>
> (d) A certificate of necessity that the estimated . . . capital costs of and the financing plan for the . . . proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new . . . electric generation facility, will be recoverable in rates from the electric utility's customers subject to subsection (4)(c).

DTE Electric's application for a CON for new construction was filed at the utility's discretion. Unlike the circumstance with pipelines regulated under 1929 PA 9 or 1929 PA 16, or a certificate of public convenience and necessity under 1929 PA 69, a utility may build generation without requesting, or receiving, a CON from the Commission, if the utility determines that it is reasonable to do so. The lack of a CON will not prejudice the recovery of reasonable and prudent costs of the plant through rate cases, once the plant is "used and useful."

But under this traditional approach, there are inherent risks—for both utilities and ratepayers—of waiting years for regulatory determinations on the need, preferred technology relative to alternatives, and costs, given the piecemeal nature of cost review and other regulatory determinations. In contrast, the CON framework, with the support of an IRP to evaluate need, options, and costs, allows for a thorough and holistic examination of these issues prior to a utility proceeding with the construction of a large capital project. The utility benefits because the CON mitigates risk by providing up-front assurance of cost recovery up to the amount approved in the CON and the ability to include financing costs in rates before the plant is considered used and useful in the provision of utility service. Ratepayers can benefit because any costs incurred over the approved amount are presumed to be imprudent. MCL 460.6s(9). While the utility could still request recovery of such costs, it would have to overcome this evidentiary presumption. Since the CON statute was enacted, no utility has pursued a large investment in new generation or upgrades to existing facilities[2] without seeking a CON.[3] Going forward, CONs are now required for generation projects 225 MW and above as part of an IRP under section 6t.

The Commission's responsibilities in evaluating an application are outlined in Section 6s(4), MCL 460.6s(4):

> Within 270 days after the filing of an application under this section, . . . the commission shall issue an order granting or denying the requested certificate of necessity. The commission shall hold a hearing on the application . . . as a contested case . . . The commission shall permit reasonable discovery before and during the hearing in order to assist parties and interested persons in obtaining evidence concerning the application, including, but not limited to, the reasonableness and prudence of the construction . . . for which the certificate of necessity has been requested. The commission shall grant the request if it determines all of the following:
>
> (a) That the electric utility has demonstrated a need for the power that would be supplied by the . . . proposed electric generation facility . . . through its approved integrated resource plan under section 6t or subsection (11).

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[2] Except environmental upgrades, which are not eligible for a CON under the law.

[3] Prior to this DTE Electric application, three CONs have been requested; of these, two have been granted by the Commission (Indiana Michigan Power Company's Cook Nuclear Plant overhaul and Upper Michigan Energy Resources Corporation new gas plant) and one was withdrawn (Consumers Energy's Thetford gas plant).

> (b) The information supplied indicates that the . . . proposed electric generation facility will comply with all applicable state and federal environmental standards, laws, and rules.
>
> (c) The estimated cost of power from the . . . proposed electric generation facility . . . is reasonable. The commission shall find that the cost is reasonable if, in the construction . . . to the extent it is commercially practicable, the estimated costs are the result of competitively bid engineering, procurement, and construction contracts[.] Up to 150 days after an electric utility makes its initial filing, it may file to update its cost estimates if they have materially changed. No other aspect of the initial filing may be modified unless the application is withdrawn and refiled. A utility's filing updating its cost estimates does not extend the period for the commission to issue an order granting or denying a certificate of necessity.
>
> (d) The . . . proposed electric generation facility . . . represents the most reasonable and prudent means of meeting the power need relative to other resource options for meeting power demand, including energy efficiency programs, electric transmission efficiencies, and any alternative proposals submitted under this section by existing suppliers of electric generation capacity under subsection (13) or other intervenors.
>
> (e) To the extent practicable, the construction or investment in a new . . . facility in this state is completed using a workforce composed of residents of this state as determined by the commission.

In addition to these statutory obligations, pursuant to MCL 460.6s(10) and (11), the Commission established requirements for CON filings (CON filing requirements) and guidance for IRPs (CON IRP guidlines) under Section 6s(11) when Section 6s was first enacted in 2008. Specifically, on December 23, 2008, in Case No. U-15896 (December 23 order) the Commission approved CON filing requirements for applications under MCL 460.6s (Exhibit A to the December 23 order) and CON IRP filing guidelines (Exhibit B to the December 23 order). On December 21, 2016, Governor Snyder signed into law Public Act 341 of 2016 (Act 341). This act took effect on April 20, 2017. Act 341 amended the CON provisions in Section 6s by allowing for certain power producers to submit alternative proposals to the Commission for consideration. In a subsequent order, issued on May 11, 2017, the Commission approved updated CON filing requirements pursuant to Act 341. Thus, the CON filing requirements approved in the May 11 order supersede the CON filing requirements approved in December 23 order, while the previously-approved CON IRP guidelines remained in effect.

Act 341 also added new IRP provisions in Section 6t. On November 21, 2017, the Commission issued an order (November 21 order) approving modeling scenarios and parameters for use in future IRP proceedings under Section 6t. On December 20, 2017, the Commission issued an order in Case Nos. U-15896 and U-18461 (December 20 order) that approved, *inter alia*, comprehensive filing requirements, procedures, and guidelines for IRPs under both Section 6s and Section 6t, going forward. These IRP guidelines supersede the CON IRP guidelines approved in the December 23 order.

There is a dispute whether the IRP guidelines, as updated in the December 20 order, apply to the instant case. As a matter of law, the Commission finds that, because this application predates the December 20 order by almost six months, these newer requirements do not apply.[4] Parties have argued that DTE Electric should have anticipated the new requirements because the company participated in the stakeholder processes in 2017 to develop the new IRP guidelines. The Commission disagrees that the guidelines were sufficiently developed to provide meaningful direction, even informally, given that the Commission was still considering important issues like high/low gas price forecast assumptions and data sources and the pre-filing public engagement requirement shortly before the Commission's order in November 2017. Moreover, it is inappropriate as a regulatory practice to move the so-called "goal posts" on the IRP guidelines during the course of this proceeding. Thus, the Commission finds that the requirements in section

[4] Whatever a company chooses to file in support of its application, the company must still provide sufficient evidence for the Commission to make the requisite findings under Section 6s(4).

6s and the associated CON filing guidelines set forth in the May 2017 order and CON IRP guidelines approved in the December 23 order apply in this proceeding.

The Commission emphasizes that the IRP guidelines approved in the December 23 order were intended to provide direction to CON applicants about the types of analyses the Commission expects to see in the filing. Importantly, simply complying with the requirements in effect at the time the application was filed does not mean that a request for a CON or an IRP will necessarily be approved. The Commission must still consider the preponderance of the evidence in making the requisite findings under Section 6s(4).

For the most part, the parties did not contest DTE Electric's compliance with the CON filing requirements set forth in the May 11 order. *See,* Exhibit A-1. To the extent that any issues were raised with respect to the CON IRP guidelines in the December 23 order, those issues are addressed, where applicable, below. *See*, Exhibits A-1 and A-11.

With respect to whether the IRP filed in this case must be "approved," MEC/NRDC/SC posit that:

> Section 6s of Act 341 also requires a utility to file an IRP in support of its CON application. The IRP is a core component of an application for a CON, as Michigan law expressly links issuing a CON to IRP approval. To receive a CON, the utility must demonstrate a need for the power that would be supplied by the proposed plant "through its approved integrated resource plan under section 6t or subsection (11)." Thus, a prerequisite for a CON is an approved IRP under one of those two sections. To approve the CON application, the Commission must find that DTE's IRP meets the seven requirements outlined in subsection 11 of Section 6s, including:
>
> > (f) An analysis of the availability and costs of other electric resources that could defer, displace, or partially displace the proposed generation facility or purchased power agreement, including additional renewable energy, energy efficiency programs, load management, and demand response, beyond those amounts contained in subdivisions (c) to (e).
>
> Importantly, while Section 6s requires an approved IRP in order to receive a CON, Section 6s does not include an approval procedure or approval standards for the

> IRP. Section 6t, on the other hand, does include an approval procedure and approval standards for an IRP. Therefore[,] the Commission can and should consider utilizing the approval procedure for Section 6t, including the identification of recommended changes, for the IRP in this case.

MEC/NRDC/SC's initial brief, pp. 7-8 (footnotes omitted).

DTE Electric responds:

> MEC/NRDC/SC's proposal is unlawful. MCL 460.6s(4)(a) plainly says "approved integrated resource plan under section 6t **or subsection (11).**" (Emphasis added). It is well established that the statutory term "or" provides a choice between alternatives. MEC/NRDC/SC's proposed misreading of MCL 460.6s(4)(a) would render the emphasized "or subsection (11)" language nugatory and violate the rule that: "Effect must be given to every word, phrase, and clause in a statute, and the court must avoid a construction that would render part of the statute surplusage or nugatory." *Book-Gilbert v Greenleaf*, 302 Mich App 538, 541; 840 NW2d 743 (2013); *Jenkins v Patel*, 471 Mich 158, 167; 684 NW2d 346 (2004) ("Courts must give effect to every word, phrase, and clause in a statute and avoid an interpretation that would render any part of the statute surplusage or nugatory[.]").

DTE Electric's reply brief, p. 5. DTE Electric further states that it does not yet have an approved IRP under Section 6t, thus the IRP under Section 6s(11) is the only option in this case.

MEC/NRDC/SC's argument appears to assume that the word "approved" modifies both an IRP "under Section 6t" as well as an IRP under "subsection (11)" of Section 6s. The Commission disagrees that an IRP under MCL 460.6s(11) must be "approved" or, alternatively, that it must be "approved" in the same manner as an IRP under MCL 460.6t.

First, MEC/NRDC/SC is correct that under the series-qualifier rule of construction, a modifier placed before a series of nouns or noun phrases generally applies to all of the items in the series. However, as the United States Supreme Court explained in *Lockhart v United States*, 136 S Ct 958; 194 L Ed 2d 48 (2016): "Whether a modifier is 'applicable as much to the first . . . as to the last' words in a list, whether a set of items form a 'single, integrated list,' and whether the application of the rule would require acceptance of an 'unlikely premise' are fundamentally contextual questions." *Lockhart*, p. 965, quoting *Porto Rico Railway, Light & Power Co v Mor*, 253 US 345, 40 S Ct 516, 64 L Ed 944 (1920) and *Paroline v United States*, 572 US ____; 134 S Ct 1710; 188 L Ed 2d 714 (2014).

In *Lockhart,* the Court affirmed the application of the last antecedent canon, which is the opposite of the series-qualifier canon: "The [last antecedent] rule provides that 'a limiting clause or phrase . . . should ordinarily be read as modifying only the noun or phrase that it immediately follows.'" *Lockhart*, p. 962, quoting *Barnhart v Thomas*, 540 US 20, 26; 124 S Ct 376; 157 L Ed 2d 333 (2003). However, the Court also observed that the application of this canon, or any other rule of construction, may be controverted by contextual or structural evidence. *Lockhart,* p. 965.

In the instant case, the Commission finds sufficient indicia in the context of Section 6s and Section 6t to reject MEC/NRDC/SC's interpretation that the Commission must "approve" DTE Electric's IRP filed under Section 6s(11). Section 6t was enacted specifically for the evaluation, and approval or disapproval of IRPs, which must be filed by all rate-regulated electric utilities within two years after April 20, 2017. Section 6t is also mandatory, whereas Section 6s, in this instance, is optional. Although a CON request may be combined with the IRP under Section 6t, the central purpose of that proceeding remains the IRP evaluation. Conversely, the purpose of Section 6s is to provide for the assessment of CON requests for new generation, the purchase or upgrade of existing facilities, or a PPA, and the IRP serves to support the requested CON. The Commission further notes that this interpretation is consistent with the CON filing requirements.[5] Moreover, once all rate-regulated utilities have approved IRPs under Section 6t, the IRP under

[5] "An integrated resource plan, as required by MCL 460.6s(11) or approved pursuant to MCL 460.6t, shall be included as an exhibit to the certificate of necessity application. The plan shall include the items listed in MCL 460.6s(11) and otherwise comply with the Commission's standards developed under that section. This subsection does not apply to an electric utility that has an approved integrated resource plan under MCL 460.6t." Part IV, Attachment A, May 11 order.

Section 6s(11) will no longer be needed. Thus, reading Section 6s *in pari materia* with Section 6t, the Commission finds that "approved" only applies to an IRP under Section 6t.

Nevertheless, assuming, *arguendo*, that the Commission must "approve" an IRP under Section 6s(11), as MEC/NRDC/SC claim, the Commission finds that DTE Electric's IRP complies with the requirements under Section 6s as discussed further in this order.[6] In addition, the Commission disagrees that DTE Electric's IRP should be evaluated using the same criteria as is provided under Section 6t. Although DTE Electric submitted a plan for longer than 10 years, and that plan includes an additional plant in 2029, the Commission must necessarily narrow the scope of its inquiry to the initial five or six years of the IRP to determine whether the proposed NGCC in 2022 meets the requirements for the findings under MCL 460.6s(4). If the Commission makes those findings with respect to a project to be in service in five years, the inquiry ends. To do otherwise would risk turning the CON proceeding under Section 6s into a full IRP proceeding that should be properly carried out under Section 6t. While the Commission finds the analysis by DTE Electric and intervenors assisted its understanding of the longer-term options, any recommendations for additional retirements, renewable energy, EE, DR, or additional fossil generation after 2022 are largely irrelevant to the issue of whether a CON should be granted for a plant that will begin construction in 2019 and is expected to begin operating in 2022. These issues, however are completely germane to DTE Electric's March 2019 IRP under MCL 460.6t.

As discussed in this order, the Commission provides guidance on how these issues must be addressed in DTE Electric's 2019 IRP filing, and further guidance for DTE Electric to consider as it pursues near and long-term options for meeting energy and capacity needs in a reliable,

[6] The Commission recognizes that prior to the 2016 amendment of Section 6s, Section 6s(4)(a) read "approved integrated resource plan that complies with subsection (11)."

affordable, and environmentally protective manner while adapting to changing market and technology conditions.

Although MEC/NRDC/SC are correct that Section 6t(8) contains detailed findings with respect to the IRP, the Commission disagrees that it should use these criteria for evaluating the IRP submitted under Section 6s. Had the Legislature intended that the Commission make such findings, it could have included them in the amendments to Section 6s under Act 341, but the Legislature did not do so. Finally, the Commission notes that in past proceedings under Section 6s, the extent of the Commission's "approval" of the IRP was to evaluate whether the application comported with the CON filing requirements and IRP guidance in effect at the time the application was filed. *See*, October 25, 2017 order in Case No. U-18244.

III. <u>APPLICATION</u>

As noted above, on July 31, 2017, DTE Electric filed an application, with supporting testimony and exhibits, requesting CONs for the construction of a 1,100 MW NGCC electric generation facility at the company's Belle River Power Plant site. Specifically, DTE Electric seeks CONs that: (1) the power to be supplied by the proposed project is needed; (2) the size, fuel type, and other design characteristics of the proposed project represent the most reasonable and prudent means of meeting that power need; and (3) the estimated $989 million capital costs of, and the financing plan for, the proposed project will be recoverable in rates from DTE Electric's customers. DTE Electric averred that its application and supporting exhibits meet the CON and IRP filing requirements of MCL 460.6s and the May 11 order.

Pursuant to the CON filing requirements, prior to submitting an application, the company must make a filing announcement and engage in a pre-application consultation process. DTE Electric complied with both requirements and no party raised an issue with the company's actions. In addition to the filing announcement and pre-consultation process, in light of the CONs DTE Electric was requesting, the company was required to comply with Sections I, III, IV, V, VI, VII.A, and VIII.A of the CON filing requirements.

DTE Electric's compliance with the applicable filing requirements is discussed below.

A. Certificate of Necessity Type

Pursuant to Section V of the Filing Requirements, DTE Electric must identify the relief requested. The utility may seek one or more of the certificates set forth in Section 6s(3). On page 1 of its application, DTE Electric stated that it is requesting CONs pursuant to Section 6s(3) of Act 341, and specifically requests the Commission issue:

(i) A certificate of necessity that the power to be supplied by the Proposed Project is needed;

(ii) A certificate of necessity that the size, fuel type, and other design characteristics of the Proposed Project represent the most reasonable and prudent means of meeting that power need; and

(iii) A certificate of necessity that the estimated capital costs of and the financing plan for the Proposed Project including, but not limited to, the costs of siting and licensing the Proposed Project and the estimated cost of power from the Proposed Project will be recoverable in rates from the Company's customers.

These certificates requested, comport with Section 6s(3)(a), (b), and (d) of Section 6s.

B. Certificate of Necessity That the Power to Be Supplied as a Result of the Proposed Construction, Investment, or Purchase Is Needed

Section VI of the Filing Requirements states that the utility shall identify the projected resource requirements, the expected timing of the requirements, along with an IRP that identifies the proposed course of action. The applicant shall either have an approved IRP under Section 6t of Act 341, or file, as part of their application, an IRP that is consistent with Section 6s(11). DTE Electric filed an IRP pursuant to Section 6s(11). Exhibit A-4 (2nd Revised). The Commission discusses issues related to load forecasts, coal plant retirements, and the need for power in more detail in this order.

C. Certificate of Necessity That the Design Characteristics of a Proposed Electric Generation Facility or Investment in an Existing Electric Generation Facility or the Terms of a Power Purchase Agreement Represent the Most Reasonable and Prudent Means of Meeting Future Power Needs

Section VII of the Filing Requirements lists 19 items the utility shall include in the CON application, if applicable. In this case, the applicable items are as follows:

1. A written description of the proposed or existing site, including identification of the municipality in which the facility will be constructed and the current use of that site

In the testimony submitted with DTE Electric's CON application, the company stated the existing Belle River Power Plant (BLRPP) location was the optimal location for a new gas plant due to available space within the 1,500 acre property, with access to water and existing infrastructure including high pressure gas pipelines and high voltage electric transmission lines. 5 Tr 1466-1468, Exhibit A-41.

2. If applicable, the age of the existing facility or facilities to be purchased or modified

DTE Electric's CON application involves new construction only, and does not include purchase or modification of an existing facility. Therefore, this item in the Filing Requirements is not applicable.

3. Expected generating technology and major systems (including major pollution control systems)

DTE Electric stated the proposed project is a nominal 1,100 MW, natural gas combined cycle plant, with advanced class technology, and best available control technology (BACT) for air emissions including selective catalytic reduction (SCR) and oxidation catalysts. 5 Tr 1470.

4. Expected nameplate capacity, availability, heat rates, expected life, and other significant operational characteristics

According to DTE Electric, the proposed facility is expected to have a nameplate capacity of approximately 1,100 MW, and with regular maintenance, is expected to have a 30-year useful life. The plant heat rate is expected to be below 6,300 British thermal units (Btu) per kilowatt-hour (kWh) and would represent the most efficient plant in the company's generation fleet, with an availability estimated to be greater than 87%. Once operating, the plant also has the capability to ramp up or down 100 MW per minute. 5 Tr 1471-1472. Additional information on the proposed plant's characteristics is discussed in subsection 7, below.

5. Fuel type and sources, including the identification and justification of fuel price forecasts used over the study period

In testimony included with DTE Electric's application, the company stated that the proposed facility could be fueled by natural gas delivered by a variety of nearby large diameter pipelines including Vector, DTE Gas Company, and Great Lakes Gas Transmission (GLGT). These pipelines provide gas sourced from multiple regions in the US from traditional supply in the Gulf, Mid-Continent and Canada, to the shale gas producing regions in the east. DTE Electric explained that fuel supply will be secured by entering into a firm gas transportation contract to ensure reliable supply and reduce price volatility. 8 Tr 2553-2555.

6. The expected annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract, and an assessment of whether some or all of the anticipated emissions and their anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives

DTE Electric provided testimony and an exhibit addressing this filing requirement. 5 Tr 1444-1445, Exhibit A-36 revised.

7. Discussion of the rationale behind facility or investment technology, fuel, capacity, and other significant design characteristics

DTE Electric commissioned HDR Engineering, Inc., (HDR) to review alternative power generation which included various energy options and plant sizes, such as natural gas fueled simple and combined cycle generation, coal-based generation with carbon capture and sequestration technology (CCS) renewable energy including biomass, wind and solar, energy storage options, nuclear energy and market purchases. 5 Tr 1461-1462.

The company screened these options based upon a levelized cost of electricity (LCOE), eliminating the highest cost options first and further eliminating options based upon a benefit cost analysis. The remaining resources were then modeled in the IRP including: natural gas CT and CC, renewable (wind and solar), demand response, storage, energy efficiency (EE or energy waste reduction (EWR)) and short-term market purchases up to 300 MWs. 6 Tr 1610-1611. As a result of this analysis, DTE Electric selected the proposed project.

The proposed project is an advanced-class generation technology, multi-shaft 2x1 combustion turbine combined cycle power plant burning natural gas fuel. 5 Tr 1470-1471. The project will consist of two combustion turbine generators and heat recovery steam generators equipped with natural gas duct burners located outdoors, which allows the use of duct firing, increasing the plant output with minimal impacts on heat rate or emissions. Exhibit A-38, Table 2-12. A steam turbine generator and some of the balance of plant equipment will be located indoors. The plant will also include best available control technology (BACT) for air emissions, including selective catalytic reduction and oxidation catalysts. 5 Tr 1470-1471.

The plant can be operated in a base load mode, an intermediate load follow mode, or at its lowest turndown mode with one CT generator off and the other CT generator operating at its minimum emission compliance limit, with generation output of about 25% of its total rated capacity. 5 Tr 1472.

The company's proposed facility and location has access to sufficient water, natural gas and electric transmission infrastructure and can be located on existing property adjacent to another electric generation plant. 8 Tr 2554-2555.

8. A description of all major state, federal, and local permits required to construct and operate the proposed generation facility or the proposed facility upgrades in compliance with state and federal environmental standards, laws, and rules

DTE Electric stated that it would obtain all required major construction and operation permits and permissions, including all permits required by federal, state and local units of government. 5 Tr 1469-1470, 1436-1441.

9. If applicable, the status of any transmission interconnection study and identification of any expected or required transmission system modifications

DTE Electric stated that it submitted its interconnection request to MISO on June 1, 2017. 7 Tr 2163. While the interconnection studies were not completed, DTE Electric provides an estimate of transmission upgrade costs.

10. If applicable, natural gas infrastructure required for plant construction and operation not located on the proposed site but required for plant construction and operation

As discussed in detail above, DTE Electric described the natural gas infrastructure required to construct and operate the proposed generation facility. 8 Tr 2553-2555.

11. If applicable, a description of modifications to existing road, rail, or waterway transportation facilities not located on the proposed site but required for plant construction and operation

According to Mr. Damon, "[t]he site also has easy access to rail, road, and international waterways; thereby alleviating transportation logistics issues." The company identified no modifications to existing rail, road or waterway transportation for the proposed project. 5 Tr 1467.

12. If applicable, water and sewer infrastructure required for construction and operation not located on the proposed site but required for plant construction and operation

DTE Electric stated that the Company has not identified a need for any additional infrastructure required for construction or operation outside the site boundaries. 5 Tr 1475.

13. A basic schedule for development and construction, which include an estimated time between the start of construction and commercial operation of the facility or facility upgrades

DTE Electric provided Exhibit A-42 that details the project construction schedule. In this exhibit, the Company expects detailed engineering to begin in the 3rd quarter of 2018 and construction to begin in the spring of 2019. The proposed project is expected to commence commercial operation during the 2nd quarter of 2022. 8 Tr 2605.

14. An estimate of the proportion of the construction workforce that will be composed of residents of the state of Michigan

DTE Electric stated that the Company estimates 90% of the craft labor will be comprised of Michigan residents. 8 Tr 2615.

15. Descriptions of the alternatives that could defer, displace, or partially displace the proposed generation facility or significant investment in an existing facility, that were considered, including a "no-build" option, and the justification for the choice of the proposed project. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization, load management, demand response, energy storage and renewable energy

DTE Electric stated that its IRP considered alternatives, such as a "no build" option, the justification for the choice for the proposed project, comparative costs of supply alternatives, EE, and renewable energy. Exhibit A-4(2nd Revised), Exhibit A-38.

16. Describe the effect of the proposed project on wholesale market competition

According to DTE Electric, the proposed project is expected to increase market competition because the 1,100 MW proposed plant is significantly smaller than the 2,100 MW of generation assets that the Company expects to retire. 7 Tr 2235-2236.

17. Any workpapers used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact

DTE Electric supplied all workpapers on a compact disk along with its application.

18. Any modeling input or output files used in developing the application, supporting testimony, and any accompanying integrated resource plan. Such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program

DTE Electric included non-confidential modeling input and output files on a compact disk along with its application. Additionally, and as previously discussed in this order, the ALJ in this case granted the discovery motion to compel on September 7, 2017 and subsequent motion to enforce on October 18, 2017 thereby directing the Company to provide all model input and output files.

19. Any other information that the applicant considers relevant

DTE provided a risk assessment in its 2017 IRP, Section 12 which is further discussed in testimony. 6 Tr 1756-1771. The company also commissioned a third party assessment of its modeling process. 7 Tr 1976-1995.

D. Certificate of Necessity That the Estimated Capital or Purchase Costs of the New or Existing Electric Generation Facility or the Investment in an Existing Electric Generation Facility Will Be Recoverable in Rates from the Electric Utility's Customers

Section VIII of the Filing Requirements states that an application seeking a CON to construct a new electric generation facility shall provide an estimate of the costs required for the specified purchase or construction, as well as projected facility operation costs. The cost estimates for the construction of a new facility shall include four items, if applicable. DTE Electric addressed the three applicable items as follows:

1. To the Extent Applicable and Available, Engineering, Procurement, and Construction Costs, Transmission Interconnection Costs, Owner's Costs, and Project Financing Costs

DTE Electric stated the estimated capital cost of the project are as follows:

Engineer Procure Construction Cost	\$879,000,000
Owner's Cost	\$ 55,000,000
Contingency Cost	\$ 55,000,000
TOTAL	\$989,000,000
Transmission upgrades	\$ 29,000,000
Gas Distribution upgrades (unknown)	
Firm Transportation costs (unknown)	

8 Tr 2608-2609, Exhibit A-43.

2. For New Construction, the Application Shall Include the Expected Typical Annual Costs Associated With Operating the Facility, Including Fuel, Operations and Maintenance, and Environmental Compliance

DTE Electric stated the estimated annual operating and maintenance costs for the proposed facility are as follows:

35 Full-time Employee (internal workforce)	
Fixed O&M including long term service agreement (LTSA)	\$11,000,000
Variable O&M including LTSA	\$ 2.47/MWh
Fuel not included	

7 Tr 2311.

3. A disclosure indicating the portion of investment included in the applicant's request for a certificate of necessity which was previously included in the applicant's rate base

DTE Electric stated that approximately "\$.4 million of capital expenditures incurred during 2011-2013 are included in approved rate base. All costs 2014-2017, totaling \$13.2 million, were disallowed by the Commission in U-18014."

In addition, the company reflected approximately \$6.5 million of cumulative project costs through 2016 in Case No. U-18255 and DTE Electric's recent rate case reflected \$26.6 million of CWIP for projected year January 2017 – October 2018 and requested inclusion in rate base without an AFUDC offset. 5 Tr 1499.

IV. OVERVIEW OF THE RECORD AND POSITIONS OF THE PARTIES

A. Overview of the Testimony

1. DTE Electric

DTE Electric sponsored the direct testimony and exhibits of 16 witnesses. Charles F. Adkins, a Vice President in the Consulting Practice of ABB Enterprise Software, Inc. (ABB), provided an independent assessment of DTE Electric's IRP models and processes, specifically testifying regarding the models, optimization, modeling scenarios, and sensitivity analyses. His qualifications and direct testimony are transcribed at 7 Tr 1970-1995. Mr. Adkins sponsored Exhibits A-12, A-13, and A-14.

Michael E. Banks, Manager, Power Generation Engineering in the Engineering Support Organization responsible for the New Gas Generation group in DTE Electric's Fossil Generation Department, provided IRP assumptions for DTE Electric's current generation portfolio, including details on locations, capacity factors, and projected retirement dates. Mr. Banks' qualifications, direct testimony, and revised rebuttal testimony are transcribed at 7 Tr 2298-2320. Cross examination of Mr. Banks can be found at 7 Tr 2321-2327.

Kevin L. Bilyeu, Principal Marketing Specialist of Energy Optimization Strategy for DTE Electric, provided an overview of the company's EE programs, including historical performance, near-term EE forecast, and the EE sensitivity analyses included in DTE Electric's IRP. Mr. Bilyeu sponsored Exhibits A-32 and A-33 and rebuttal Exhibits A-69 through A-71. Mr. Bilyeu's qualifications, direct testimony, and rebuttal testimony are transcribed at 7 Tr 1996-2056. Cross-examination of Mr. Bilyeu can be found at 7 Tr 2057-2086.

Timothy A. Bloch, a Principal Financial Analyst in DTE Energy Corporate Services LLC's Regulatory Affairs organization, testified about renewal of Public Utility Regulatory Policies Act

(PURPA) power purchase agreements (PPAs) and new PPAs. Mr. Bloch's rebuttal testimony is transcribed at 8 Tr 2342-2352.

Kevin J. Chreston, DTE Electric's Manager, IRP and Modeling, testified regarding DTE Electric's modeling, analysis, and results for its IRP. Mr. Chreston sponsored Exhibits A-4 (2nd Revised) through A-10 (3rd Revised), and A-11. Mr. Chreston's qualifications, direct and rebuttal testimony are transcribed at 6 Tr 1706-1839. Cross-examination of Mr. Chreston is at 6 Tr 1840-1955.

William H. Damon III, a Senior Vice President and Director for HDR's Strategic Consulting Practice, testified regarding the natural gas generation technologies considered by DTE Electric, and he described the process the company used in its siting analysis. Mr. Damon also provided information on the technical specifications of the proposed NGCC plant. Mr. Damon's qualifications and direct testimony are transcribed at 5 Tr 1456-1476.

Phillip W. Dennis, Manager, Regulatory Economics for DTE Electric testified on the expected impact of the proposed project on customer rates. Mr. Dennis's qualifications and direct testimony can be found at 8 Tr 2589-2593.

Irene M. Dimitry, DTE Electric's Vice President of Business Planning & Development, provided an overview of the company's CON requests, the IRP, and costs associated with the project. Ms. Dimitry's qualifications and direct testimony are transcribed at 6 Tr 1589-1623.

Dan O. Fahrer, DTE Electric's Director of Major Enterprise Projects Platforms, testified regarding the costs of the proposed NGCC plant along with the construction schedule and workforce composition. Mr. Fahrer's qualifications and direct testimony can be found at 8 Tr 2601-2616.

Derek D. Kirchner, Supervisor –Demand Side Management, Business Planning & Development for DTE Electric, discussed DTE Electric's demand response (DR) programs including interruptible air conditioning (IAC), planned pilot DR programs, DR assumptions used in the IRP models, and the company's experience with distributed generation (DG) programs. Mr. Kirchner's qualifications and direct and rebuttal testimony are transcribed at 7 Tr 2091-2113. Cross-examination of Mr. Kirchner can be found at 7 Tr 2114-2149.

Markus B. Leuker, DTE Electric's Manager of Corporate Energy Forecasting, testified concerning the company's projected sales, demand, and output forecasts for 2016-2040. Mr. Leuker's qualifications and direct testimony are found at 8 Tr 2400-2420.

Barry J. Marietta, DTE Electric's Supervisor of the Emissions Quality Group, Environmental Management & Resources, provided information on environmental compliance for the company's current generating fleet and for the proposed project. Mr. Marietta's qualifications and direct and rebuttal testimony are transcribed at 5 Tr 1431-1452.

Terri L. Schroeder, DTE Electric's Manager of Business Development in Renewable Energy, testified concerning DTE Electric's current renewable portfolio and updates based on 2016 PA 342 (Act 342) requirements. Ms. Schroeder's qualifications and direct testimony can be found at 8 Tr 2463-2476.

Don M. Stanczak, Vice President, Regulatory Affairs for DTE Electric, provided rebuttal testimony on DTE Electric's pending depreciation case and the effects of the Tax Cuts and Jobs Act (TCJA) of 2017 on the company's IRP. Mr. Stanczak's rebuttal testimony is transcribed at 5 Tr 1485-1492.

David Swiech, Manager, Planning and Procurement in DTE Electric's Fuel Supply Department, testified concerning DTE Electric's current fuel procurement practices and provided forecasted fuel price assumptions for the IRP. Mr. Swiech's qualifications and direct testimony are transcribed at 8 Tr 2541-2556.

Theresa M. Uzenski, Manager of Regulatory Accounting for DTE Electric and DTE Gas Company, testified concerning the company's proposed rate making and accounting treatment of financing cost recovery for the proposed plant. Ms. Uzenski's qualifications and direct testimony are transcribed at 5 Tr 1494-1499.

Edward P. Weber, Senior Technical Advisor and Project Manager in HDR's System Protection and Studies Section, discussed transmission issues including how the company acquires transmission service and the process used by the Midcontinent Independent System Operator Inc. (MISO) to evaluate and approve transmission projects. Mr. Weber sponsored Exhibits A-34 and A-35. Mr. Weber's qualifications and direct and rebuttal testimony are transcribed at 7 Tr 2154-2174. Cross-examination of Mr. Weber can be found at 7 Tr 2175-2215.

Angela P. Wojtowicz, Director of DTE Electric's Generation Optimization Department, provided an overview of the company's application, including a discussion of MISO resource adequacy requirements and the company's current capacity portfolio. Ms. Wojtowicz sponsored Exhibits A-24 through A-27, and rebuttal Exhibits A-50 through A-63. Her qualifications, revised direct testimony and revised rebuttal testimony can be found at 7 Tr 2221-2255. Cross-examination of Ms. Wojtowicz is transcribed at 7 Tr 2256-2293.

2. Commission Staff

The Staff presented testimony of seven witnesses. Karen M. Gould, an Auditor in the Energy Waste Reduction Section of the Commission's Electric Reliability Division, testified regarding the Staff's recommendations for EE implementation in DTE Electric's CON proceeding. Ms. Gould sponsored Exhibits S-3.1 through S-3.3. Ms. Gould's testimony is transcribed at 5 Tr 238-253.

Jesse J. Harlow, a Public Utilities Engineer in the Renewable Energy Section of the Commission's Electric Reliability Division, testified about DG modeling scenarios that the company did not include in its presentation. Mr. Harlow sponsored Exhibit S-5.1 and his testimony can be found at 5 Tr 262-270.

Olumide O. Makinde, an Economic Analyst in the Resource Adequacy and Retail Choice section of the Commission's Financial Analysis and Audit Division, testified regarding the Staff's review of DTE Electric's load and natural gas price forecasts and an assessment of the company's IRP planning methods and models. Mr. Makinde sponsored Exhibit S-2.1 through S-2.7. Mr. Makinde's testimony is transcribed at 5 Tr 218-237.

Robert F. Nichols II, Manager of the Revenue Requirements Section of the Commission's Financial Analysis and Audit Division, testified about the company's request for current recovery of financing costs of the proposed project. Mr. Nichols' testimony is transcribed at 6 Tr 1575-1580. Cross-examination of Mr. Nichols can be found at 6 Tr 1581-1585.

Paul A. Proudfoot, Director of the Commission's Electric Reliability Division, provided an overview of the Staff's position on DTE Electric's application. Mr. Proudfoot's testimony is transcribed at 5 Tr 173-187.

Naomi J. Simpson, a Public Utilities Engineer in the Generation and Certificate of Need Section of the Commission's Electric Reliability Division, testified regarding DTE Electric's compliance with the requirements of MCL 460.6s. Ms. Simpson sponsored Exhibit S-1.1 through Exhibit S-1.11. Ms. Simpson's second corrected direct testimony can be found at 5 Tr 188-217.

Katie J. Smith, an Economic Analyst in the energy waste reduction (EWR) Section of the Commission's Electric Reliability Division, provided the Staff's recommendations regarding DR resources and programs. Ms. Smith sponsored Exhibits S-4.1 through S-4.3. Ms. Smith's testimony is available at 5 Tr 254-261.

3. Attorney General

The Attorney General sponsored the testimony of Philip DiDomenico, Managing Consultant at Daymark Energy Advisors. Mr. DiDomenico reviewed DTE Electric's application, testimony, and exhibits and provided recommendations for future IRP proceedings. He sponsored Exhibits AG-1 through AG-20. Mr. DiDomenico's testimony is transcribed at 6 Tr 1519-1571.

4. Association of Businesses Advocating Tariff Equity

ABATE sponsored the direct and rebuttal testimony of Nicholas L. Phillips, an Associate with Brubaker & Associates. Mr. Phillips provided an analysis and recommendations with respect to DTE Electric's request for CONs for an NGCC. Mr. Philips' testimony and rebuttal testimony are transcribed at 5 Tr 273-311.

5. Environmental Law and Policy Center *et.al.*

ELPC, *et al.*, sponsored the testimony of Kevin Lucas, Director of Rate Design at the Solar Energy Industries Association. Mr. Lucas provided an overview of solar energy issues relevant to this proceeding and provided a review of DTE Electric's IRP modeling and risk assessment. He sponsored Exhibits ELP-1 through ELP-56, and his qualifications and direct testimony are transcribed at 5 Tr 654-874.

R. Thomas Beach, principal consultant of the consulting firm Crossborder Energy, presented recommendations concerning DTE Electric's request for a CON for a new gas plant. Mr. Beach sponsored Exhibits ELP-58 through ELP-62. His corrected direct testimony and rebuttal testimony are transcribed at 5 Tr 896-994.

Michael B. Jacobs, Senior Energy Analyst for the Union of Concerned Scientists, testified regarding the manner in which DTE Electric addressed energy storage in the company's IRP. Mr. Jacobs' qualifications and direct testimony are transcribed at 5 Tr 875-895.

Phillip Jordan, a principal with BW Research Partnership, provided an economic impact analysis of jobs in the renewable energy and EE sectors. He sponsored ELP-63 and his testimony is transcribed at 5 Tr 995-998.

6. Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club

MEC sponsored the testimony of Josh Berkow, Principal Power Systems Engineering Consultant for RINA Consulting, who testified regarding transmission options for DTE Electric. Mr. Berkow sponsored Exhibits MEC-88 and MEC-89, and his testimony is transcribed at 5 Tr 544-550.

MEC/NRDC/SC sponsored the testimony of five witnesses. Avi Allison, an Associate with Synapse Energy Economics, reviewed the renewable resource and capacity price modeling assumptions in DTE Electric's IRP, as well as the company's risk analysis. Mr. Allison sponsored Exhibits MEC-49 through MEC-71 and his testimony is transcribed at 5 Tr 444-499.

Robert Fagan, Principal Associate at Synapse Energy Economics, provided an evaluation of DTE Electric's modeling for its IRP. Mr. Fagan sponsored Exhibits MEC-90 through MEC-108, and his testimony is available at 5 Tr 551-590.

Chris Neme, Principal of Energy Futures Group, a consulting firm specializing in and renewable EE energy, testified regarding the EE assumptions included in DTE Electric's IRP. Mr. Neme sponsored Exhibits MEC-17 through MEC-39. Mr. Neme's testimony is transcribed at 5 Tr 357-410.

Dale Osborn, a consulting electrical engineer with specialization in transmission planning, testified concerning transmission options, resource adequacy, import limits, and DTE Electric's request for proposals (RFP) for generating assets. Mr. Osborn sponsored Exhibits MEC-72 through MEC-87, and his testimony can be found at 5 Tr 500-543.

George W. Evans, President of Evans Power Consulting, Inc., testified regarding DTE Electric's Strategist modeling analyses and presented the results of the modeling that he performed. Mr. Evans sponsored Exhibits MEC-1 through MEC-6, and MEC-9, MEC-10, and MEC-12 as well as confidential Exhibits MEC-7C, MEC-8C, MEC-11C, and MEC-13C through MEC 16C. Mr. Evans' direct, rebuttal, and supplemental testimony is transcribed at 5 Tr 316-356.

7. Michigan Cogeneration Venture Limited

Kevin R. Olling, Vice President of Energy Supply and Marketing for MCV testified regarding DTE Electric's competitive bid process related to market-based alternatives to the company's proposed project. Mr. Olling sponsored Exhibits MCV-1 and MCV-2. His testimony is transcribed at 5 Tr 607-623.

8. Michigan Energy Innovation Business Council

EIBC sponsored the testimony of Hannah Hunt, a Senior Analyst, Industry Data & Analysis, at the American Wind Energy Association. Ms. Hunt provided cost and performance updates for wind energy and made recommendations concerning DTE Electric's IRP. Ms. Hunt's testimony is transcribed at 5 Tr 627-650.

MEC/NRDC/SC and EIBC sponsored separate parts of the testimony of Douglas B. Jester, a Partner of 5 Lakes Energy LLC. Mr. Jester testified regarding DR, PURPA resources, and customer-requested renewable energy under MCL 460.1061. Mr. Jester sponsored Exhibits MEC-40 through MEC-48, and his testimony is transcribed at 5 Tr 411-443.

B. Positions of the Parties

1. DTE Electric

DTE Electric contends that it met all of the filing requirements that were in place at the time the company submitted its application for the CONs. Further, DTE Electric maintains that the preponderance of the evidence demonstrates that the power to be supplied by its proposed project is needed due to the retirement of eight coal-fired units[7] scheduled for 2020-2023. The retirement of these units was necessitated by age, the cost of compliance with environmental regulations, and the company's goal to reduce carbon emissions from its generation fleet. DTE Electric points to its analysis that shows that retirement of the units is more economical than further investment; however, the power lost from these units will need to be replaced in order to meet MISO reliability requirements. DTE Electric observes that only ABATE disagrees that the units should be retired.

Next, DTE Electric argues that given the import limits for capacity, the company cannot obtain sufficient power outside of local resource zone (LRZ or Zone) 7 and firm capacity purchases from outside Zone 7 do not address the local clearing requirement (LCR) inside the zone. According to DTE Electric, the company's IRP indicates a need for 472 MW of additional capacity in 2022, increasing to 1,266 MW in 2023 after the remaining Tier 2 units are retired. DTE Electric noted that, because it must demonstrate that it meets its capacity requirements four years into the future under MCL 460.6w, it cannot rely on the MISO planning reserve auction (PRA) capacity prices to model capacity cost and that the company correctly used a bilateral capacity purchase forecast in its modeling. DTE Electric pointed out that the Commission has

[7] The units to be retired are River Rouge Unit 3, St. Clair Units 1-3 and Units 6-7, and Trenton Channel Unit 9 (Tier 2 units). St. Clair Unit 4 was retired while this case was pending.

expressed concerns about system reliability in the wake of aging generation plants and planned and unplanned retirements.

DTE Electric contends that its proposed project is the most reasonable and prudent means to meet the power deficit, claiming that no other party proposed a specific, alternative project. DTE Electric argues that its IRP modeled several load forecasts and considered both supply-side and demand-side resources in developing a plan that calls for 1.5% energy efficiency savings, 15% renewable energy by 2021, 125 MW of additional demand response (DR), and one 1,100 MW NGCC plant in 2022 and second 1,100 MW plant in 2029. DTE Electric highlighted the steps it undertook in developing various modeling scenarios, as well as the sensitivity analyses that it ran. In addition, DTE Electric updated its assumptions in 2017 (2017 Reference Case) to address the effects of new energy legislation and more recent market prices, load forecasts, and fuel prices. The company claims that its modeling resulted in the most reasonable and prudent solution to address the company's long-term load requirements.

DTE Electric maintains because of MISO planning requirements, import constraints, and the paramount need for reliability, transmission alternatives are of limited use in replacing the proposed project, observing, "it is imperative to have reliable capacity within LRZ 7 to, at a minimum, meet the LCR. Accordingly, as capacity resources in LRZ 7 retire (like the River Rouge, St. Clair and Trenton Channel plants are planned to do, removing ~ 1,822 MW of capacity), new capacity resources need to be built in LRZ 7." DTE Electric's initial brief, p. 24. DTE Electric further argued that "[e]ven if transmission import limits could be expanded in a timely manner, the Company would be taking considerable risk if it simply assumed that there would be available capacity at reasonable cost in neighboring MISO zones." *Id.* p. 59.

DTE Electric undertook a siting study and highlighted the advantages of the selected location (adjacent to the Belle River Power Plant) including access to significant natural gas infrastructure. DTE Electric issued requests for proposals (RFPs) for engineering, procurement, and construction (EPC) and power island equipment (PIE) for the proposed project. To the costs from the successful bid, DTE Electric added a 6% contingency consistent with acceptable construction practices. The company also issued an RFP to determine if there were market-based options that would be more economical than the proposed plant. DTE Electric contends that its RFP and conforming bid requirements were reasonable, consistent with resource constraints, and recognized the significant risks inherent in relying on a long-term PPA. As a result, the company did not receive any conforming bids that were more cost-effective than the proposed project.

With respect to its IRP submitted in support of its proposed project, DTE Electric argues that the forecasts it used for load, fuel prices, and wind and solar resource costs were based on reliable forecasting methods (load, fuel cost) or on the company's historical costs (wind and solar). DTE Electric disputed that customer-requested renewable energy under MCL 460.1061 will be a significant driver of additional renewables over the life of the IRP. The company added that it appropriately evaluated alternative resource options, including no build, additional renewable energy, EE, and DR, that could defer, displace, or partially displace the proposed project. DTE Electric asserts that "even the most aggressive EE and DR alternatives would still leave a substantial shortfall[,]" adding that "[a]cross all of the cases modeled, the modeling tool never selected additional renewables beyond the minimum statutory target of 15%." DTE Electric's initial brief, pp. 46-47. For EE, the company pointed out that the IRP includes 1.5% savings, which is above the statutory mandate of 1%, and that the DR savings included in the plan are consistent with achievable DR potential, pointing out that the recommendations for additional EE and DR, made by other parties, are overly optimistic or otherwise inappropriate. DTE Electric also dismissed generation available from qualifying facilities (QFs) under PURPA, noting that there are concerns about the viability of some existing PURPA QFs as well as questions about changes to the law. DTE Electric also questioned the reliability of renewable energy compared to the proposed project, which has significant capability to meet customers' needs for varying amounts of power.

Finally, DTE Electric argued that its risk analysis, and an independent review, confirmed that the proposed NGCC plant was the most reasonable and prudent means to meet the company's future power needs. In addition, DTE Electric averred that the project will comply with all environmental requirements and will provide benefits to local communities and the state. Accordingly, DTE Electric concluded that the Commission should grant the requested CONs and find that the capital and financing costs of the project are recoverable in rates.

2. Commission Staff

The Staff recommends that the Commission approve DTE Electric's requests for CONs under Section 6s(3)(a), (b), and (d) noting, however, that there are sufficient deficiencies in the company's analysis that the Commission could decide otherwise and might direct the company to refile its application, or it might approve a smaller plant. The Staff recommends that in the company's March 2019 IRP filing under MCL 460.6t, the Commission should require DTE Electric to file a stronger case that complies with the updated filing requirements. In addition, in order to avoid the need to build additional capacity in the long term, the Staff recommends that the company be required to base its DR and EE levels on the more rigorous statewide potential studies, rather than on the company's potential studies.

3. Attorney General

The Attorney General urges the Commission to carefully review DTE Electric's CON requests, and proceed with caution in light of the cost that will be borne by customers in future rate case proceedings. The Attorney General claims that although the company has adequately shown a need for the power in this case, in future IRPs, DTE Electric should be required to undertake a more robust and transparent analysis. The Attorney General further suggested that in the future, the Commission should demand a better evaluation of the potential for capacity to be supplied from resources outside of MISO LRZ 7, noting his concerns about DTE Electric's refusal to consider resources outside of Zone 7, despite available import capacity.

The Attorney General also supported DTE Electric's request for a CON finding that the proposed plant is the most reasonable and prudent means of supplying the power, notwithstanding deficiencies in the company's IRP and a lack of transparency in the modeling process. The Attorney General expressed reservations about DTE Electric's RFP process for alternatives to a new build, but he nevertheless noted that no alternative proposals were presented in the proceeding. Finally, the Attorney General opposed DTE Electric's request to include contingency costs as part of its project, contending that the plain language of Section 6s precludes the approval of such costs in a CON.

4. Association of Businesses Advocating Tariff Equity

ABATE contends that DTE Electric provided incomplete, inaccurate, and contradictory analyses in support of its application, and therefore the Commission should deny the requested CONs. Specifically, ABATE argues that due to the passage of the TCJA in late 2017, DTE Electric's Tier 2 unit retirement analysis, IRP, and forecasted costs for the proposed NGCC plant are now incorrect. ABATE points out that both Mr. Chreston and Mr. Nichols admitted that the tax-related inputs to the various models did not reflect the material changes brought about by the TCJA.

ABATE further posits that, given expected changes to federal environmental regulations under the current federal administration, the assumptions about additional pollution controls required for the company's coal fleet are now unreliable. ABATE also argues that because DTE Electric's retirement analysis for the Tier 2 units used a different model, and different inputs from those used in the company's IRP and CON analyses, the cost of early retirement versus new build cannot be appropriately compared. ABATE further contends that many of the cost inputs to DTE Electric's various models were from 2016 and should be updated in a new IRP.

5. Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club

MEC/NRDC/SC point out that DTE Electric's proposal must not only comply with MCL 460.6s and the Commission's filing requirements as established by the May 11 order, but the Commission must also ensure that the proposal complies with the Michigan Environmental Protection Act (MEPA) MCL 324.1701 *et seq.* even though Section 6s does not expressly mention MEPA.

According to MEC/NRDC/SC, the Commission should reject DTE Electric's CON because the company's analyses were deficient and inconsistent. MEC/NRDC/SC points to the filing requirements that state that the IRP shall propose a "course of action," maintaining that the course DTE Electric plans to follow is in fact a step backward and is inconsistent with the company's own evidence in this case.

MEC/NRDC/SC also criticize DTE Electric's failure to incorporate additional amounts of renewable energy, EE, and DR in its projections, claiming that DTE Electric used incorrect or unsupported assumptions, limited the size options that the model could pick for these resources, and restricted the timing to implement these resources until 2022.

MEC/NRDC/SC also question DTE Electric's analysis of transmission options, arguing that: (1) the company's analysis of current transmission capability is substantially out-of-date; (2) the company failed to analyze capacity import at all; (3) DTE Electric's refusal to consider resources outside of Zone 7 in its RFP was unjustified; and (4) the company's assumed restriction of imports to 300 MW of spot purchases in its modeling was unreasonable. MEC/NRDC/SC further posit that DTE Electric's transmission analysis did not comply with the requirements of MCL 460.6s(11)(f) or the IRP filing requirements under Exhibit B to the December 23 order.

Next, MEC/NRDC/SC contend that, "DTE's IRP compares optimal to non-optimal resource plans, resulting in misleading information and non-transparent decision-making." Specifically, MEC/NRDC/SC argue, "the record shows that DTE rejected the optimal resource plan in the least-cost sensitivity– the 2% Energy Efficiency case – on the basis it would delay its proposed NGCC and add demand response resources. DTE instead selected a less-optimal and more-costly 1.5% Energy Efficiency case for its proposed course of action." MEC/NRDC/SC's initial brief, p. 76. MEC/NRDC/SC point out that Strategist produces a number of possible outcomes for each given scenario and ranks them in order of cost from lowest to highest. MEC/NRDC/SC acknowledge that there are often good reasons not to pick the optimal plan selected by the program, but DTE Electric failed to identify which plan was the optimal plan in each of its Strategist runs, and failed to support its selection when it chose a plan with a lower ranking.

Next, MEC/NRDC/SC criticize DTE Electric's 2017 Reference Case, noting that the company erroneously used a much lower heat rate for the NGCC in its update, thereby making the plant appear more economical than it is. Although the company claimed to have addressed the error, and that it did not change the results of the analysis in any event, MEC/NRDC/SC maintain that it "further undermine[s] the accuracy and integrity of the IRP modeling and analysis." MEC/NRDC/SC's initial brief, p. 83.

MEC/NRDC/SC contend that DTE Electric's rate impact analysis, required under the December 23 order, was misleading. MEC/NRDC/SC state that DTE Electric opted to base its analysis on a comparison between a no-build option, which would rely on costly market purchases of capacity and energy and the capital and operating cost of the proposed NGCC plant. MEC/NRDC/SC claim that this comparison is deceptive and unreasonable because the rate impact analysis in the filing requirements does not call for a comparison, DTE Electric described the no-build option as infeasible, and there were several other viable options presented on which to base a comparison.

Finally, MEC/NRDC/SC argue that an additional reason for the Commission to deny the requested CONs is the fact that the company's own modeling shows that increasing energy efficiency to 2% in the near term would delay the plant until 2023 or later, sufficient time for DTE Electric to submit a more robust and transparent IRP under MCL 460.6t. In addition, MEC/NRDC/SC contend that the option to delay the plant until 2023 is more economical than DTE Electric's preferred plan, and other parties presented reasonable and prudent plans that would delay the plant even further, to 2026 or 2030, resulting in significant savings to customers.

6. Environmental Law and Policy Center *et al.*

ELPC *et al.* argue that DTE Electric's analysis was so fundamentally flawed that the Commission should deny the requested CONs. ELPC *et al.* argue that DTE Electric's failure to explore reasonable alternatives to its proposed NGCC plant means that the company did not meet its burden, under Section 6s(4)(d), to show that its proposal is the most reasonable and prudent means to meet its power need. Specifically, ELPC *et al.*, contend that DTE did not accurately model the availability and cost of solar and wind resources, and significantly understated the achievable potential for DR and EE. In addition, DTE Electric simply ignored any obligations it has under PURPA and assumed there would be no additional QF power added to its portfolio. Citing Federal Energy Regulatory Commission (FERC) Order 841, ELPC *et al.* also point out that the company failed to consider adding battery storage, despite how quickly the technology is developing.

ELPC *et al.* provided an alternative portfolio, which according to ELPC *et al.* showed that the NGCC could be delayed until 2027 and would save ratepayers an estimated $1.2 billion. Finally, ELPC *et al.* take issue with DTE Electric's risk analysis, claiming that the company did not properly model fuel-price risk or the risk that the proposed NGCC plant could become a stranded asset as other technologies evolve and become less costly.

7. Michigan Energy Innovation Business Council

EIBC urges the Commission to deny the requested CONs on several grounds. First, EIBC contends that DTE Electric has failed to demonstrate that the power is needed as required under MCL 460.6s(4)(a). According to EIBC, DTE Electric's IRP fails to account for energy and capacity that the company is required to purchase under PURPA through both new and renewed contracts, and it fails to include customer-requested renewable energy under MCL 460.1061. EIBC also contends that DTE Electric's IRP does not comply with Section 6s(11) because the company's analysis includes incorrect information concerning the cost of wind energy. EIBC further claims that DTE Electric, while using the correct source, used the wrong capacity credit for wind, resulting in wind as a more costly resource than it actually is. EIBC argues that although DTE Electric proposes to add additional wind energy to its portfolio, the timing of these additions, during and after the phase-out of the federal Production Tax Credit (PTC), increase the cost of wind substantially and unnecessarily. Finally, EIBC argues that in failing to make a reasonable analysis of the alternatives that could potentially displace all or a portion of DTE Electric's proposed NGCC plant, the company did not make the requisite showing under MCL 460.6s(4)(d) that its proposal was the most reasonable and prudent means to supply power.

8. Ann Arbor

Ann Arbor claims that DTE Electric's assumption, that PURPA contracts with existing QFs will not be renewed, is unreasonable because it "creates an artificial need for new capacity, and threatens to displace existing QF capacity with DTE's own new generating capacity." Ann Arbor's reply brief, p. 2. Ann Arbor points out that the company's rationale, namely that PURPA might change or be repealed before contract renewals occur, and therefore power from existing QFs should be excluded, is groundless because the more realistic assumption is that PURPA will continue in effect. Ann Arbor further argues that DTE Electric's other justification for omitting existing QF capacity from its IRP, namely that the Ann Arbor facilities may not be operating when their contracts end, is also a baseless assumption. Similarly, Ann Arbor claims that DTE Electric assumed, unreasonably, that there will be no new PURPA capacity added to the company's generation portfolio, despite the must-purchase obligation under PURPA and recent Commission activity resetting avoided costs. Accordingly, Ann Arbor argues that DTE Electric failed to demonstrate the full need for capacity to be filled by the proposed project.

V. FINDINGS AND CONCLUSIONS UNDER MCL 460.6s(4)

Although the parties elected, for the most part, to organize their briefing consistent with the three CONs that DTE Electric requested, the Commission observes that the findings it must make under Section 6s(4) are more detailed and therefore more suitable for the discussion and analysis in this order. Moreover, while the IRP is mentioned specifically under Section 6s(4)(a), the Commission notes that the IRP modeling undergirds multiple aspects of the Commission's inquiry, thus, except for the portion of the IRP addressing the company's unit retirement analysis, the remainder of the IRP is addressed in detail, *infra*.

Given the abbreviated, 270-day time-frame allowed for this proceeding, coupled with a record that is more voluminous than usual, not all of the material presented can be discussed in detail. The various parties' summaries of the evidence and arguments in support of their respective positions are fully set forth in their pleadings and briefs, and the basis for the parties' claims may be found in the testimony and exhibits. Thus, although the Commission has considered the entire record in arriving at its findings and conclusions stated below, only those arguments, testimony, and exhibits necessary for a reasoned analysis of the disputed issues will be specifically addressed in this order.

A. Has DTE Electric demonstrated a need for the power that would be supplied by the proposed electric generation facility through its integrated resource plan?

The applicable CON filing requirements and CON IRP guidelines do not articulate how the "need" for power is demonstrated. As discussed in the load forecasting section below, however, the CON IRP guidelines require a forecast of economic indicators, electric load forecasting, peak demand, available generation, fuel costs, and environmental costs. Forecasts should include among other things, effects of demand-side management, environmental limitations, planning reserve margin and system reliability requirements, or other legislative or societal developments that will likely impact future energy requirements.

As noted above, DTE Electric avers that, as a result of its plan to retire eight coal-fired units between 2020 and 2023, it has demonstrated a need for the proposed NGCC plant in 2022. Specifically, DTE Electric explained that "the Company will require 472 MW of additional capacity to meet its projected [planning reserve margin requirement] PRMR beginning in 2022 . . . This shortfall grows to 1,266 MW in 2023 after the announced coal plant retirements are complete." DTE Electric's initial brief, p. 23. ABATE questions whether the units actually should be retired in light of recent tax law and environmental policy changes.

In its reply brief, p. 19, DTE Electric explains:

> In 2014, the [Environmental Protection Agency] EPA finalized regulations on cooling water intake under section 316(b) of the Clean Water Act ("CWA"). In 2015, the EPA issued its final rule related to water discharge or effluent limitation guidelines ("ELG") for steam electric power generators. The updated requirements in section 316(b) and the ELG impact the future operations of the Company's coal generating units (6T 1604), with ELG compliance capital expenditures estimated at $370 million, and 316(b) compliance costs exceeding $100 million.

DTE Electric added that in addition to stricter and more costly environmental regulations, the company's decision to retire the Tier 2 units was driven by the age and operating cost of the units, as well as the company's goal, supported by its customers, to move to a lower-carbon generation portfolio.

Mr. Marietta testified that in addition to ELG and 316(b) regulations, the company's generating units are also subject to the National Ambient Air Quality Standards (NAAQS) and the Coal Combustion Residuals (CCR) Rule. 5 Tr 1436. Mr. Marietta continued, discussing the regulatory requirements and the impact of the ELG, 316(b), NAAQS, and CCR rules on the company's coal generating fleet. 5 Tr 1436-1441. Mr. Marietta testified that DTE Electric took the Clean Power Plan (CPP) into account in developing its retirement analysis, noting that the CPP was stayed at the time DTE Electric was analyzing unit retirement. Mr. Marietta also testified that the company recently announced plans to reduce its carbon emissions by 30% in the early 2020s, 45% by 2030, 75% by 2040, and over 80% by 2050 compared to 2005 carbon emissions. 5 Tr 1446.

Mr. Chreston testified that DTE Electric performed an economic analysis on all of the company's coal units to evaluate the impact of investing capital to bring each unit into compliance with the ELG and 316(b) requirements versus early retirement. First, units with similar operating characteristics were grouped together and then an economic analysis was done to determine the net present value (NPV) of early retirement (i.e., 2023 or before) as opposed to keeping the units operating for five years after the compliance date for the ELG regulations (i.e. 2028) 6 Tr 1729-1730. Mr. Chreston concluded that "[t]he economics from this study indicate that it is better to retire St. Clair, Trenton 9, and River Rouge before the Environmental Retrofits are required in 2023 and it is better to keep operating Belle River and Monroe and make them compliant to the ELG and 316(b) regulations." 6 Tr 1731.

Mr. Chreston presented a chart (Figure 2) demonstrating that the Tier 2 units had an NPV ranging from negative $31 million to negative $84 million, whereas Belle River and Monroe showed positive NPVs of $232 million and $2.085 billion respectively. *Id.* Mr. Chreston also ran sensitivity analyses on all of the units or unit groups (except Monroe) evaluating higher capital costs for compliance, low market prices for capacity, and a CO_2 sensitivity analysis. Mr. Chreston presented his results in Figure 3, which demonstrates that except under low market capacity prices, and except for St. Clair Unit 7 and Trenton Channel, it is more economical to retire the Tier 2 units. Even Trenton Channel and St. Clair Unit 7, show only a modest positive NPV under the low capacity price scenario. 6 Tr 1732.

Mr. Phillips testified that because DTE Electric's retirement evaluation was conducted in early 2016, assumptions related to taxes and environmental regulations are no longer correct and must be updated. 5 Tr 275. Mr. Phillips raised several concerns about the company's retirement analysis, including a shift in the approach to environmental and tax policies under the new administration, the need to update modeling inputs to reflect more current demand and commodity prices, and the fact that the retirement analysis did not reflect increased depreciation expense resulting from the retirements. With respect to the last point, Mr. Phillips testified that DTE Electric would be requesting an addition $149 million in depreciation expense related to steam generation in the company's next rate case. 5 Tr 279-282.

Mr. Phillips pointed out that DTE Electric's coal retirement analysis includes CPP compliance, despite the court-ordered stay, adding that the EPA has stayed compliance with the ELG pending further review, similar to the situation with the CPP. According to Mr. Phillips, if the ELG is rescinded or appreciably revised, DTE Electric's cost estimate for compliance may be significantly overstated. Even if the rules are not extensively changed, Mr. Phillips claimed that the substantial change in the corporate tax code due to the TCJA will make environmental compliance less costly. 5 Tr 285.

Mr. Phillips also took issue with the inconsistency between the modeling programs used for DTE Electric's coal retirement analysis (PROMOD) versus its IRP (Strategist). Mr. Phillips observed that not only did the company use different programs, but it also used different assumptions for load forecasts and commodity prices between the two analyses. 5 Tr 293.

Mr. Phillips admitted that DTE Electric's proposal to retire older coal units and replace them with gas is not unique to Michigan and is in fact occurring nationwide. Nevertheless, Mr. Phillips contended that because Michigan has limited import capability, more resources will need to be built in-state. Thus, a decision to retire units before the end of their useful lives has more significant implications for customer rates in Michigan. 5 Tr 294-295.

Mr. Phillips opined that because the company has not definitively established that the retirement of the coal units is in the public interest, the Commission should deny DTE Electric's request for the CONs. Further, Mr. Phillips recommended that the Commission direct DTE Electric to rerun its coal unit retirement analysis to reflect known changes to federal tax and environmental policy and update its IRP modeling scenarios to comport with the Commission's most recent filing and IRP modeling requirements. 5 Tr 276.

In rebuttal, Mr. Marietta pointed out that although the CPP has been stayed by the U.S. Supreme Court, the ELG is only targeted for review and possible revision. In the meantime, "the regulation remains in place with final compliance dates at the end of 2023. The outcome of the ELG review is not expected to be known until fall of 2020 and any assumptions made by Witness Phillips are purely speculative." 5 Tr 1451. Similarly, Mr. Chreston pointed out that although the CPP has been stayed, the rule has not been withdrawn, thus:

> It would be imprudent to change the Company's plans based on speculation. Not moving forward with the retirement of the Tier 2 units in the early 2020s would put these units at risk in regards to ELG, and CPP if it becomes effective. Additionally, the exact requirements for the Company's plants related to [sulfur dioxide] SO_2, National Ambient Air Quality Standards (NAAQS) are unknown, there is no reason to believe that retirement dates later than currently planned by DTE Electric for the Tier 2 plants are feasible based on the environmental regulations at this time. Waiting for a final determination would limit the amount of time needed to secure an optimal replacement.

6 Tr 1822.

Mr. Stanczak addressed the depreciation and TCJA issues raised by Mr. Phillips, testifying that DTE Electric's depreciation case is still pending, and the company may not be seeking a \$149 million increase in depreciation expense in its next rate case. Mr. Stanczak noted that the Staff and ABATE have proposed depreciation rates that differ significantly from the company's recommended rates. 5 Tr 1490. In addition, Mr. Stanczak stated that the increased depreciation expense is not exclusively related to coal unit retirement; some portion is related to higher plant retirement costs. Mr. Stanczak added:

> [T]he Company uses the Group Method of depreciation and generally does not track depreciation reserves within each utility account down to the individual plant level. . . . Consistent with the Group Method, at the time an individual plant retires, any theoretical undepreciated plant balances will be recovered through the process of resetting depreciation rates for the remaining plants in the group. Thus, ABATE's claim is erroneous because under the Group Method, depreciation rates are not plant specific, depreciation expense will be recovered over the life of all similar assets, and the impact to depreciation rates for certain accounts cannot be made in isolation.

5 Tr 1491.

Mr. Stanczak agreed with Mr. Phillips that the TCJA's reduction of deferred taxes will have a significant effect on the company's revenue requirement in the future; however, he disputed whether it has any impact in this proceeding, noting that the remeasurement of deferred taxes does not affect plant that goes into service after January 1, 2018.

Mr. Chreston testified that with respect to the coal retirement analysis, the TCJA affects the deferred tax liability balance, pre-tax marginal cost of capital, and discount rate. The sum of these effects is expected to be minimal in the results of the retirement analysis "because all three impacts are applied to both the base case and the change cases." Therefore, "[a] revision in the Coal Retirement Analysis is unwarranted." 6 Tr 1823.

Responding to ABATE's concerns about the different analytical tools used for the retirement analysis and IRP, Mr. Chreston explained that the retirement analysis was undertaken in the initial phase of project planning, and that the use of PROMOD modeling was appropriate. Mr. Chreston added that "[a]ny further optimization using Strategist was proved to be highly unlikely through the IRP process, and would have made the case for retirement even stronger." 6 Tr 1825.

Mr. Beach also responded to ABATE's claims, opining that the TCJA would have a lesser impact on resource planning cases than on revenue requirements set in a rate case. In this IRP, Mr. Beach maintained that all resource options would be affected more or less equally by the new tax rates. Mr. Beach further testified that even if the ELG costs are removed from DTE Electric's analysis, the NPV of early retirement of the units is still positive. 5 Tr 984, note 8. Mr. Beach also points out that many industrial customers, some of whom are ABATE members, are seeking more renewable energy and are not advocating that older coal units remain in operation. 5 Tr 987-988.

Mr. Fagan similarly testified that DTE Electric's latest modeling demonstrates that even if the CPP and ELG were rescinded, continued operation of the Tier 2 units remains uneconomical. In response to Mr. Phillips' suggestion that updated load and commodity forecasts would affect the retirement analysis, Mr. Fagan agreed, but indicated that the projected decrease in demand and lower capacity and energy price forecasts compared to 2016 makes the economics of early retirement of these units even more favorable. 5 Tr 596-599.

The Commission finds that ABATE's claims should be rejected.[8] First, the Commission agrees with DTE Electric that ABATE's assertions about the future status of various federal environmental policies and regulations are speculative. As the company argues, it would be unreasonable and potentially much more costly if the company were to assume that either the CPP or the ELG will be withdrawn or rescinded. And regardless of the EPA's actions, there would likely be potentially protracted litigation that would extend well beyond the period in which decisions would need to be made about the retirement of these plants. Further, as Mr. Fagan testified:

> [U]nder DTE's 2017 Reference Case, each Tier 2 unit other than St. Clair 7 incurs net losses on behalf of DTE's customers in every year of its remaining life. St. Clair 7 breaks even in only 4 years and incurs net NPV losses of $10 million over its remaining life. **Importantly, under this scenario none of the Tier 2 units**

[8] The Commission's determinations in this section are based in part on its finding that DTE Electric's load forecast is reasonable. The company's load forecast is discussed below.

> **incur any costs associated with ELG or CPP compliance.** Each unit avoids ELG compliance costs by retiring prior to the December 31, 2023 compliance deadline. Since the 2017 Reference case assumes that the CPP does not begin until 2027, these units also avoid any CPP compliance costs. Yet they remain uneconomic.

5 Tr 597 (emphasis supplied, notes omitted). In addition, as DTE Electric states, environmental compliance was not the only consideration in its retirement analysis; the company also took into account the age of the retiring plants and their reliability and operating costs. The Commission has also issued several decisions in rate cases expressing concern over the cost-effectiveness of these marginal units.[9] The Commission agrees, therefore, that the most reasonable and prudent course of action is to retire the Tier 2 units by 2023 as DTE Electric proposes.

Next, the Commission rejects ABATE's argument that the TCJA has a significant, albeit unquantified, effect on DTE Electric's retirement analysis. As Mr. Chreston explained in cross examination:

> To continue to use the existing coal units, there was very little capital that would be needed to be expended to update for environment technology, for instance, while the proposed project had significant amounts of capital that need to be expended to put the proposed project in place.
>
> And it's my understanding of reviewing the marginal cost to capital and deferred taxes, that the heavy capital utilization for the proposed project would be more affected by the changes in the jobs act or jobs and tax cuts act, and that would make actually the proposed project even more favorable compared to retiring the units due to the heavy capital utilization of installing the proposed project. So I don't have a specific number. But if the delta was going to change from my prior analysis, it would be more favor for the proposed project than keeping the Tier 2 units in service.

6 Tr 1844-1845.

Next, the Commission finds unpersuasive ABATE's claim that increased depreciation costs make unit retirement less economical. As DTE Electric indicated, the company's current

[9] *See*, e.g., January 31, 2017 order in Case No. U-18014 and April 18, 2018 order in Case No. U-18255.

depreciation case is pending and, under the company's group method of depreciation, the actual retirement date of a specific unit is immaterial. Mr. Fagan similarly points out that previously incurred capital costs should not be included in an economic analysis because unit retirement will not affect these sunk costs.

Finally, the Commission accepts DTE Electric's explanation that using PROMOD for the retirement analysis produced sufficiently robust results that further optimization with Strategist was unnecessary. PROMOD is an appropriate modeling tool for retirement analyses of this nature.

In a related issue, Mr. Fagan suggested that DTE Electric should consider early retirement of some of the Tier 2 units. Mr. Fagan testified that because there is sufficient available capacity in MISO, in the near term, market purchases of capacity would be more economical than running the Tier 2 units until 2020, 2022, or 2023. 5 Tr 585-587. Specifically, Mr. Fagan suggested that River Rouge Unit 3 could be retired by May 31, 2018. 5 Tr 588.

In rebuttal, Ms. Dimitry testified that DTE Electric will be evaluating possible earlier retirement of uneconomic Tier 2 units in its 2019 IRP, as required by the modeling parameters set forth in the November 21 order. In addition, Ms. Wojtowicz testified that an operator may not simply decide to retire or suspend operation of a unit because "local resources support the reliable operation of the transmission system and may be required to keep it within acceptable thermal and voltage limits." 7 Tr 2253. Ms. Wojtowicz explained the process in MISO for evaluating reliability, which occurs after the operator submits an Attachment Y Notification of Generator Change of Status, noting that a unit may not retire until it is assured that the transmission system will not be affected. *Id.*

The Commission agrees with DTE Electric that, although there is a possibility that one or more of the Tier 2 units might retire early, any plans to do so should await the outcome of the company's 2019 IRP analysis and the results of MISO's Attachment Y reliability study. Other matters such as workforce and local government tax impacts may also be considered in a decision of this magnitude.

The Commission finds DTE Electric demonstrated a need for power, both energy and capacity, pursuant to Section 6s(4)(a) for purposes of granting a certificate under 6s(3)(a), largely due to the retirement of the Tier 2 units representing approximately 2,000 MW of capacity. As discussed further in this order, the Commission observes the "power need" may also entail the need for local voltage support and other reliability benefits to address the closing of numerous coal plants and integration of other resources such as wind and solar energy.

B. Does the information supplied indicate that the proposed electric generation facility will comply with all applicable state and federal environmental standards, laws, and rules?

DTE Electric outlined how the proposed gas plant would comply with state and federal environmental standards, laws, and rules. Mr. Marietta testified that in addition to water intake and discharge regulations that also apply to coal-fired generation, an NGCC must also comply with New Source Performance Standards (NSPS) under 40 CFR Part 60, Subpart 10KKKK and National Emission Standards for Hazardous Air Pollutants (NESHAP) under 40 CFR Part 63, Subpart YYYY. 5 Tr 1442. According to Mr. Marietta, the proposed project will comply with all state and federal environmental regulations.

Mr. Damon testified that DTE Electric does not anticipate the need for any federal permits, except from the Federal Aviation Administration (FAA), and will be required to obtain the following major federal, state, and local permits: (1) Permit to Install (PTI)/New Source Review (NSR) Air Permit from the Michigan Department of Environmental Quality (MDEQ) pursuant to Mich Admin Code, R 336.1201; (2) Modification of the Belle River National Pollutant Discharge Elimination System (NPDES) Permit for Water Discharge; (3) Joint Permit for Work in Inland

Lakes and Streams, Great Lakes, Wetlands, Floodplains, Dams, High Risk Erosion Areas, and Critical Dune Areas from MDEQ; (4) Soil Erosion and Sediment Control and Storm Water (NPDES II) Permits and Site Plan Preliminary Approval from the St. Clair County Drain Commission; (5) Building Permits from East China Township, St. Clair County; and (6) FAA authority for interference to flight path determination. 5 Tr 1469-1470.

Mr. Proudfoot concurred with Mr. Marietta that the proposed project would comply with all state and federal environmental rules as required under MCL 460.6s(4)(b). Ms. Simpson likewise testified that, based on the Staff's review of the company's state and local permit list, the proposed project will meet all state and federal environmental requirements. 5 Tr 197-198; Exhibits S-1.2 and S-1.3. Ms. Simpson recommended that DTE Electric submit a final list of all required environmental and construction permits and an affidavit that all necessary permits have been acquired.

In rebuttal, Mr. Marietta apparently disputed the need to report on the permits, testifying that all required permits were listed in the company's initial filing and if the Staff had concerns about any omissions, it should have raised these concerns specifically. 5 Tr 1450. In its initial brief, DTE Electric contends that all permits will be publicly available and that "[p]ermitting is a dynamic and time consuming process that can take years and may require modifications." DTE Electric's initial brief, p. 79, note 101, citing 5 Tr 1450.

The Commission agrees with the company and the Staff that, based on the information supplied, the proposed electric generation facility will comply with all applicable state and federal environmental standards, laws, and rules. The Commission also agrees with the Staff's minor request that the company keep the Commission apprised of the status of the permitting process as recommended by Ms. Simpson. As the company itself points out, the permitting process is dynamic and there may be modifications to the initial permit applications. Thus, requiring DTE Electric to file a list of necessary permits, updated as necessary, and an affidavit that all permits have been obtained is not an unreasonable request.

C. Is the estimated cost of power from the proposed electric generation facility reasonable?

Under MCL 460.6s(4)(c), "The commission shall find that the cost [of the proposed generation facility] is reasonable if, in the construction or investment in a new or existing facility, to the extent it is commercially practicable, the estimated costs are the result of competitively bid engineering, procurement, and construction contracts[.]" In addition to the cost information required in the CON filing requirements as discussed above, the CON IRP guidelines require DTE Electric to provide estimated costs of developing potential generating resources including cost components attributable to plant capital costs, EPC, financing, specific and generalized transmission upgrades, and owner's costs. DTE Electric was also required to provide estimated costs of operating potential generating resources including fuel, operations and maintenance (O&M), and environmental compliance. December 23 order, Exhibit B, p. 3.

Mr. Fahrer described the proposed project, explaining that it will be located on 40 acres of company-owned property adjacent to the Belle River Power Plant. Mr. Fahrer testified that the project will be sited near existing transmission lines and high pressure gas pipeline infrastructure. Mr. Fahrer stated that DTE Electric intends that the project be commercially available by June 2022, in time to meet the summer peak load requirements. Construction is anticipated to begin in spring 2019. 8 Tr 2605, Exhibit A-42.

Mr. Fahrer explained the different options for contracting, ranging from owner-managed to lump-sum turnkey (LSTK). According to Mr. Fahrer, "large combined cycle projects are principally contracted for in today's market based on either an owner furnished Power Island

Equipment (PIE) and Balance of Plant [BOP] EPC approach, or full wrap EPC option." 8 Tr 2606. After considering the costs and risk trade-offs, Mr. Fahrer explained that:

> The Company will employ an experienced EPC contractor to integrate the Owner selected PIE, provide the balance of plant specifications, provide engineering, and construct the Proposed Project. Under the BOP EPC approach, the EPC will assume the performance risk associated with integration of the PIE and balance of plant equipment with a premium to assume that risk. The Company considers the EPC's premium to be warranted for assuming this risk and will evaluate the risk and cost premium for the EPC to assume a full wrap LSTK contract. The contractual arrangement with the EPC will be a fixed price contract.

8 Tr 2607.

Mr. Fahrer indicated that the company is "pursuing a contracting strategy based on Fixed Price Owner Furnished Equipment PIE Agreement and a EPC Balance of Plant Fixed Price agreement[,]" using competitive bidding processes for both the PIE and EPC. Mr. Fahrer stated that the company was also soliciting bids for a full-wrap option from EPC contractors. 8 Tr 2607-2608.

Mr. Fahrer estimated the capital cost of the project at $989 million, including the EPC cost of $879 million, owner's cost of $110 million which includes contingency of $55 million. Exhibit A-43. In addition, transmission upgrades of approximately $29 million will be required but are not included in the capital cost for the CON. Mr. Fahrer pointed out that a more definitive cost estimate will be developed when final contract negotiations are completed after the RFP process. 8 Tr 2610.

Ms. Simpson disagreed with DTE Electric's proposal to include 6% of estimated capital costs, or $55 million, as contingency. Ms. Simpson testified that the contingency amount was based on DTE Electric's risk register which "includes 29 risk event descriptions that are evaluated for probability and potential cost impact." 5 Tr 203, Exhibit S-1.8. Ms. Simpson recommended that three line items in the risk register be disallowed. Two of the disallowances concern risks that could have been addressed by updating the CON at the 150-day point, which the company chose not to do. The third involves equipment or project scope changes after negotiations are complete. Ms. Simpson noted that because the project scope is determined at the beginning, and because DTE Electric assigned this item the lowest risk score, the contingency associated with this item should also be removed from the project cost estimate. In addition, Ms. Simpson pointed out that the contracting approach the company proposes shifts the majority of risk from the company to the contractor. Accordingly, the Staff recommended that DTE Electric's proposed contingency costs be reduced by $37.2 million, and the Commission should approve $951.8 million in CON costs. 5 Tr 204-206.

Mr. Damon disagreed with the Staff's recommendation to reduce contingency, specifically the Staff's suggestion to remove $12 million for project scope changes. Mr. Damon testified, "Our experience has shown that no project has been completed with zero change orders associated with equipment selection and design changes from this early stage. Despite best efforts to identify a detailed scope at this early stage of the project, scope decisions will still be required during detailed design and execution." 5 Tr 1480.

The Attorney General agreed with the Staff that contingency should be removed, contending that the statute does not support inclusion of these costs.

The Commission finds that the base cost of the project of approximately $934 million was the result of a fair and reasonable competitive bid process for the PIE and EPC, and there does not appear to be any serious dispute about this issue. Accordingly, the Commission finds that the cost of the proposed project is reasonable. In addition, the Commission agrees there should be some allowance for contingency, and finds persuasive the Staff's explanation that DTE Electric will bear minimal risk based on the type of contract the company intends to enter into. Therefore, the

Commission adopts the Staff's proposed contingency amount and approves $951.8 million for costs associated with the construction of the proposed project. This equates to a cost of $865.3 per kilowatt (kW). The Commission notes this amount does not include amounts for transmission upgrades, which are FERC jurisdictional and subject to review as part of the MISO transmission planning process and ITC's Attachment O formula rate review process.

It bears emphasizing that Act 341 changed important provisions regarding the regulatory standard for any costs ultimately incurred by the utility above the amount approved in the CON. While the 2008 law applied a "reasonable and prudent" presumption for cost over-runs up to 110% of the approved amount, the law now provides that any amount over the approved amount is presumed imprudent. Thus, the utility could still seek to recover amounts, if any, above $951.8 million but it would be required to rebut this presumption.

D. Does the proposed electric generation facility represent the most reasonable and prudent means of meeting the power need relative to other resource options?

As the Commission stated above, the primary support for a utility's request for a CON under Section 6s(4)(d) is the IRP. In determining whether the proposed plant is the "most reasonable and prudent" relative to other resource options under 6s(4)(d), the Commission considered the IRP and its underlying assumptions and consideration of alternatives, as well as modeling and other analyses presented by the parties on substitutes for the proposed plant. These alternatives fall into three major categories: (1) incremental renewable energy, EE, DR, and energy storage; (2) PPAs or unit acquisition; and (3) electric transmission possibilities including additional capacity to import power from outside the local resource zone. Thus, the Commission addresses IRP assumptions, modeling, and results here as well as a discussion of alternatives to the proposed plant. Section 6s(11) sets out the various components of an IRP, which the Commission addresses in order, *ad seriatim*.

1. Long-term Forecast of DTE Electric's Load Growth under Various Reasonable Scenarios.

The CON IRP guidelines specify that the IRP shall include a forecast of economic indicators, electric load including customer load and sales by customer class, peak demand, available generation, fuel costs, and environmental costs. The guidelines outline numerous factors to consider in the load forecast but do not specify specific forecasting methodologies or high/base/low load growth levels. The methodologies and critical assumptions must be provided.

Mr. Leuker testified concerning DTE Electric's method for forecasting future sales, which he averred is consistent with accepted industry standards, and which has been consistently accurate. 8 Tr 2408, Exhibit A-19. According to Mr. Leuker, the company's sales forecasting method includes: (1) analysis of residential class demand considering 39 appliances or appliance groups, number of households, appliance saturation, and electric use by appliance; (2) regression analyses for the commercial and industrial (C&I) class by type of customer; (3) a forecast of other electric sales (street lighting and traffic signals); and (4) the application of the hourly electric load model (HELM) to forecast annual peak demand system annual load shape. 8 Tr 2410-2418. Mr. Leuker also considered economic forecasts and projected population growth or decline.

As inputs to the IRP models, Mr. Leuker provided a reference scenario, a high load sensitivity analysis, a low load sensitivity analysis, and an updated 2017 reference scenario. Exhibit A-17. The high load analysis assumes that energy efficient lighting has reached peak market penetration, and electric vehicles, auto and steel manufacturing, and data centers increase demand in the residential and industrial sectors. The low load sensitivity analysis assumes a population decrease, auto plant closures, and more customer self-generation. 8 Tr 2419-2420.

Mr. Leuker testified that overall, in the Reference Case, residential class sales are expected to decrease 0.2% annually through 2040, commercial sales are forecast to increase 0.1% annually, industrial class sales are expected to increase 0.0% through 2040, other sales are forecasted to decrease by 0.1% annually, and choice sales are expected to stay the same over the plan period. 8 Tr 2405-2417. With respect to peak demand, DTE Electric forecast a compound annual growth rate (CAGR) of -0.2% per year through 2040.

Mr. Neme took issue with DTE Electric's load forecast, testifying that DTE Electric embedded 1.15% incremental EE savings in its forecast, noting that the higher the baseline savings the company uses, the less impact higher levels of EE will have under different modeling scenarios. 5 Tr 373. Mr. Neme suggested that the company's use of historical EE savings for its projection was problematic because: (1) DTE Electric only used regression analysis for C&I energy savings and not for forecasting residential energy sales, which comprised over half the company's energy savings since 2009; (2) the company did not used regression-based modeling for all of its C&I sales; (3) DTE Electric's regression analysis, which assumes 1.15% EE annual savings, includes years prior to 2009 when the company was not implementing EE programs; (4) the company's forecast of EE savings for residential customers was incomplete and did not account for future residential EE savings. 5 Tr 373-376.

Mr. Neme testified that, in developing its load forecast, DTE Electric should have removed the historical effects of EE programs explaining:

> Any elements of its forecast that are not based on statistical analysis of historic sales data, such as its residential end use forecast, should be assumed not to include any embedded future program impacts absent compelling statistical data and analysis to the contrary. This way, the Company's base case reference forecast would only include impacts of historic efficiency programs – and no impacts from any new programs. That would then allow the Company to characterize the impacts of a full range of future efficiency program savings levels and allow its model to select the least cost alternative from among them.

5 Tr 377.

In rebuttal, Mr. Leuker testified that he made the adjustments recommended by Mr. Neme and then added a 1.50% EE assumption. Mr. Leuker testified that the result was a higher sales forecast for both residential and total sales in the 2016 Reference Case. 8 Tr 2423-2424. In addition, Mr. Leuker explained that a comparison of the company's forecasted sales to load forecasts produced by the Energy Information Administration (EIA) and MISO show that the company's 2016 Reference Case is consistent with these projections, whereas Mr. Neme's analysis is an outlier. 8 Tr 2424.

Mr. Makinde testified that in the Staff's opinion, "the Company's projected load growth expectations in the various scenarios are appropriate[,]" further noting, "[w]hen compared side by side, the Company`s forecast in Exhibit A-17 and that of the EIA, Staff found that the CAGRs for the Company and the EIA, are within a reasonable range of each other in all the cases." 5 Tr 227 (footnote omitted), Exhibit S-2.2.

In their brief, MEC/NRDC/SC point to discrepancies between Mr. Leuker's presentation of energy and peak demand in Exhibit A-17 and these projections as shown in Exhibit A-10. According to MEC/NRDC/SC, "not only do the peak demand values in the two exhibits not match up, but the changes in peak demand over the planning period move in opposite directions." MEC/NRDC/SC's initial brief, p. 18.

In response, DTE Electric highlighted Mr. Chreston's testimony about the difficulty the company encountered in attempting to match its presentation in Exhibit A-10 to the Commission's CON IRP guidelines. The company further explains: "Exhibit A-10 shows the 2017 reference Scenario **bundled** peaks with 1.5% energy efficiency **taken out**, while Exhibit A-17 shows the 2017 reference Scenario **service area** peaks with 1.5% energy efficiency **embedded**." DTE

Electric's reply brief, p. 41. DTE Electric adds that Exhibit A-10 and A-17 serve different purposes and "depict two entirely different representations of the peak demand." *Id.*

The Commission finds that DTE Electric provided a reasonable forecast of projected load growth under various scenarios. Specifically, the company provided a 2016 Reference Scenario, a high load sensitivity analysis, a low load sensitivity analysis, and an updated 2017 Reference Scenario all of which were grounded in reasonable assumptions. Mr. Neme's proposed modifications to the company's load forecast resulted not only in a higher residential sales projection but also produced a forecast that was inconsistent with forecasts by MISO and the EIA. Accordingly, the Commission finds that DTE Electric's load forecasts comport with MCL 460.6s(11)(a) and the CON IRP guidelines.

2. The Generation Technology Proposed, Proposed Capacity, and Projected Fuel and Regulatory Costs under Various Reasonable Scenarios.

The primary disputes here relate to the fuel costs and the size of the proposed plant as discussed below. With respect to fuel price forecasts and associated fuel price risk, the IRP guidelines require the applicant to provide information on estimated fuel costs and conduct scenario analyses to test different forecasts and assumptions. Unlike the new IRP guidelines under Section 6t, MCL 460.6t, the IRP guidelines applicable to this proceeding do not provide any direction on the use of specific fuel price data sources, parameters around high-base-low price forecasts for scenario and sensitivity analysis in the modeling, or risk assessment methodologies. December 23 order, Exhibit B.

Mr. Swiech provided delivered fossil fuel price forecasts for each existing generation facility and fuel type for the IRP process.[10] For the natural gas price forecast for the proposed NGCC

[10] Mr. Swiech's coal and oil fuel price forecasts are not disputed.

plant, Mr. Swiech testified that, for the first five years, the company used the same forecasting method it employs for its power supply cost recovery (PSCR) annual plan filings. For the long-term forecast, the company used a long-term Henry Hub price forecast plus a delivery cost adder. 8 Tr 2551.

For the proposed NGCC plant, Mr. Swiech testified that the company forecasted fuel prices for both combustion turbine (CT) and NGCC using the Belle River peaker gas prices as a proxy. Mr. Swiech noted, however, that an NGCC is expected to have firm transportation and storage costs estimated at $18.5 million for transportation and $12 million for storage. 8 Tr 2553. Exhibits A-28 and A-29.

Mr. Swiech testified that the annual delivered fuel cost is forecasted to range from $3.24 to $7.57 per million Btu (MMBtu) from 2022 through 2040, again relying on the Belle River peakers as a proxy for the variable fuel costs and projected fixed fuel costs of $15.7 million for transportation and $4.5 million for storage. 8 Tr 2555, Exhibit A-30. Mr. Swiech explained that he used New York Mercantile Exchange futures for the first five years of the forecast and then used a long-term Henry Hub forecast from PACE Global Energy Services, LLC (PACE). 8 Tr 2552. Mr. Chreston modeled a 2016 Reference Scenario along with a low natural gas price scenario and a high natural gas price scenario. 6 Tr 1739-1740. In order to mitigate fuel price volatility, Mr. Swiech testified that DTE Electric intends to enter into firm transportation and storage agreements. 8 Tr 2548, 2554.[11]

Mr. Beach testified that the uncertainty and potential volatility of future natural gas prices, which comprise over half of the life-cycle costs of the NGCC, make DTE Electric's proposed

[11] Issues raised by Mr. Beach and Mr. DiDomenico concerning the company's arrangements with the NEXUS Pipeline are addressed below.

plant too risky. 5 Tr 897. Mr. Beach provided a graph of natural gas prices at the Henry Hub over the past several decades noting that price spikes occur regularly, highlighting the most recent spike that occurred during the polar vortex event in January-March 2014. 5 Tr 914.

Mr. Beach took issue with some of the assumptions used in the company's forecast, testifying that "DTE's reliance on more than one or two years of forward prices is questionable due to the thinly-traded forward markets after the initial two years." 5 Tr 915. Mr. Beach added that the long term forecast from EIA is much higher than the proprietary forecast that DTE Electric presented. According to Mr. Beach, under the EIA forecast, the levelized cost of the power from the plant increases by 15%. 5 Tr 916.

Mr. Beach also took issue with DTE Electric's ($.13) per MMBtu projection of its basis (i.e., the difference between the Henry Hub price and the Mich Con City Gate price) for 2023. Mr. Beach explained that this difference was based on a sample of just one day, and is projected to increase (become more negative) over time. Mr. Beach presented Figure 5, which demonstrates that, over the past 10 years, the Mich Con City Gate basis differential has consistently been higher than was projected by DTE Electric. 5 Tr 919-920.

Mr. Beach suggested that DTE Electric could address the risk of future high gas prices by "contract[ing] today for future natural gas supplies at today's forward gas prices, and then set aside in risk-free investments (U.S. Treasury notes) the money needed to buy that gas in the future." 5 Tr 916. However, Mr. Beach went on to explain "there is an additional cost of this approach, compared to purchasing gas on an 'as you go' basis over time and using the money that did not have to be set aside for alternative investments that yield a higher return[.]" 5 Tr 916. Mr. Beach calculated the additional cost to eliminate gas price uncertainty as $86 million per year over 20 years, an amount that would increase the cost of the gas plant by 25%. 5 Tr 917-918.

Mr. Makinde indicated that the company's forecast for the reference case and low-natural gas price scenario were consistent with other industry projections. However, the company's high natural gas price forecast was not. According to Mr. Makinde, after applying a statistical test to the company's forecasts, compared to EIA forecasts, for the reference and low gas price scenarios, "[t]he CAGR are within 0.003% of each other." But, "[r]egarding the high gas price sensitivity, the Company's natural gas price CAGR (2017 to 2035) is 7.7%, however, EIA is projecting a 9.3% natural gas price CAGR[.]" 5 Tr 231. According to Mr. Makinde, "if the Company has not adequately modeled a high gas price sensitivity, it's possible that the Company is underestimating the net present value of revenue requirements in the event that gas prices rise closer to the EIA's high gas price scenario compared to the Company's forecasts." 5 Tr 232, Exhibit S-2.3. Thus, if gas prices are higher than the company modeled, the proposed NGCC may not be the most reasonable and prudent alternative. Mr. Makinde therefore recommended that the company update its high gas price modeling in its 2019 IRP filing.

In rebuttal, Mr. Swiech opined that Mr. Beach did not critique the company's method for forecasting natural gas prices, testifying that DTE Electric has compared its PSCR forecasts to Henry Hub actual prices from 2009-2015, finding that the company's forecast was more accurate than the EIA forecast. 8 Tr 2560, Exhibit A-64. With respect to Mr. Beach's critique of DTE Electric's projection of the Henry Hub-Mich Con City Gate differential, Mr. Swiech testified that "[t]he decline of the MichCon City Gate basis is driven by real market changes, specifically the dramatic growth of production in the Utica/Marcellus shale region and the increasing transportation capacity between that region and the Midwest." 8 Tr 2562, Exhibit A-65.

Mr. Chreston testified that he was unable to replicate Mr. Makinde's CAGR calculation for the High Gas Price scenario, noting that the corresponding workpaper did not match the Staff's calculation, "for the EIA high gas case should be 8.3% and the correct number for the CAGR calculation for the DTE case should be 7.7%. This would put the difference between the two cases at 0.6% instead of 1.6%." 6 Tr 1818.

In its initial brief, the Staff contends that DTE Electric's claim is unsupported and incorrect. The Staff reiterated that "Staff took the average of the EIA high gas case annual growth rate over the same number of years as that of the Company's high gas case to derive the 9.3% (lines 2 to 20 of column (d) of Second Corrected Exhibit S-2.3). The difference between the two cases is 1.6% as shown in Exhibit S-2.3." Staff's initial brief, p. 19.

The Commission finds that DTE Electric adequately supported its fuel price forecast consistent with the December 23 CON IRP guidance. Although there is some dispute over the company's high gas price projection, the company nevertheless provided a forecast that was 40% higher than the reference forecast. 8 Tr 2564. The Commission agrees that DTE Electric's fuel price forecasting method has been approved in numerous PSCR proceedings as reasonable, and that method has proven accurate over time. Moreover, the company has plans, through firm transportation and storage agreements, to mitigate short-term price spikes. As Mr. Swiech explained:

> While the Company's existing natural gas fired generating facilities are currently supplied primarily though interruptible supply arrangements, the Company expects that electric generation in MISO will become more dependent on natural gas as a source of fuel for base load generation in the future. As this occurs, DTE Electric will enter into firm gas supply and gas transportation contracts as needed to ensure electric reliability. For example, DTE Electric entered into a Precedent Agreement with NEXUS Gas Transmission to provide firm natural gas transportation starting upon the in-service date of the pipeline. DTE Electric's agreement with NEXUS is for 30,000 [dekatherms] Dth per day of transportation capacity, increasing to 75,000 Dth per day upon in-service of gas-fired generation facilities. DTE Electric committed to firm gas transportation capacity from the Utica and Marcellus shale region because this nearby region has new and growing production with substantial supply and competitive pricing. Prices for natural gas from this region are expected to remain amongst the lowest in the country for the foreseeable future.

8 Tr 2548-2549. And the Commission agrees with Mr. Swiech's observation that new development of Marcellus/Utica shale gas portends relatively low gas prices for the long term, and the company's access to other sources of gas supply including Canada, the Gulf Coast, and Colorado provide an additional hedge in the event prices increase in northern Appalachia. The Commission further observes that the company will be required to provide an analysis consistent with the November 21 and December 20 orders in its 2019 IRP filing.

The Commission recognizes that fuel costs over the long term are a significant risk associated with the proposed project. As explained by DTE Electric, however, the Commission observes that there are numerous factors that mitigate fuel price volatility in Michigan generally and specifically in relation to this plant including access to multiple gas producing markets, pipeline capacity, long-term contracting and hedging options, and robust gas storage. 8 Tr 2553. The superior heat rate of this plant will also ensure maximum efficiency in the conversion of natural gas to electricity.

Turning to the issues regarding the proposed generation technology and capacity, Mr. Damon addressed the features of the proposed plant and the consideration of alternatives such as a gas-fired combustion turbine, smaller sized natural gas combined cycle plant, and energy storage. Mr. Damon explained that:

> A combined cycle power plant is based on a topping cycle wherein fuel is burned in a combustion turbine that exhausts to a heat recovery steam generator, and a bottoming cycle where the generated steam is used in a traditional steam turbine. For clarity, combined cycle configurations are denoted as 1x1, 2x1 or 3x1 were [sic] the first and last digits represent the number of combustion and steam turbines respectively.

5 Tr 1461. Mr. Damon testified that for the alternatives analysis HDR considered other generation technologies to evaluate their merits, costs, production, and environmental impacts. Size

considerations ranged from 1 MW to 1,400 MW. *Id.*, Exhibit A-38, Exhibit A-4 (2^{nd} Revised). The technologies that were evaluated included five simple cycle combustion turbine options and five combined cycle options. Simple cycle units are typically used as peakers, while combined cycle units are able to function as intermediate or base load generators, and typically are larger capacity as a result. Exhibit A-4 (2^{nd} Revised) shows that the combined cycle plants have improved fuel efficiency relative to simple cycle units, and in most cases have lower capital costs on a $/kW basis. DTE Electric considered five generic natural gas combined cycle options in its IRP, including F-class and H-class (2x1 and 3x1) technologies.

Mr. Damon provided an overview of the proposed project, noting that the plant is expected to be available 87% of the time and that "[c]ombined cycle power plants are amongst the most reliable forms of utility scale power generation technologies." 5 Tr 1471. Mr. Damon testified that the heat rate of the plant is projected to be at or below 6,300 Btu per kWh, and will be DTE Electric's most efficient generating station. According to Mr. Damon, "The plant can be operated in base load mode or dispatched in an intermediate mode load follow mode, and as needed, at its lowest turndown mode with one [combustion turbine generator] CTG off and the other CTG operating at its Minimum Emission Compliance Limit (MECL) resulting in a generation output that is about 25% of its total rated capacity." 5 Tr 1472.

Mr. Banks testified that:

> The Proposed Project plant will be able to adjust its electrical output by 100MW/minute, enough to quickly power 20,000 households per minute, over a range of 800MW. This means that as the electrical demand adjusts up and down the plant will operate in a flexible and reliable manner to meet the electrical demands of customers.

7 Tr 2320 (footnote omitted).

According to Exhibit A-4 (2nd Revised), the proposed 2x1 H-class plant is more fuel efficient and has a higher capacity factor than all of the other options considered, except for the 3x1 option. Capital costs for the 3x1 H-class plant were $987 per kW versus $1,055 per kW for the 2x1 H-class option. Although the 3x1 plant would be less expensive on a per kW basis, it would be more expensive in total, it would result in excess capacity relative to the company's need, and it would take longer to build (42 months instead of 36).

The Staff raised the question of whether it is preferable to combine a smaller plant with additional EE and DR. Mr. Banks explained:

> [T]he size of the plant has been selected based on the Integrated Resource Planning capacity need. CCGTs are designed and built in blocks based on the number of combustion turbines that are being used in conjunction with the heat recovery steam generators and the steam turbine. It is typical for advanced class CCGT plants to increase their output capability in 550MW blocks. That is, for each combustion turbine installed the output is increased by 550MW when included in a combined cycle arrangement. Plant size is selected based on these standard designs to promote cost minimization, efficiency, and reliability. When the Proposed Project construction is completed and the unit is dispatched into MISO, the plant will operate more efficiently and effectively than the other forms of electrical generation to meet customer demand.

7 Tr 2316-2317.

Mr. Beach testified that the H-class plant is a risky investment given the lack of data on the new class of advanced gas turbines, claiming there is little operating experience to date. 5 Tr 929. On rebuttal, Mr. Damon responded that the proposed plant is the latest evolution of gas turbine technology with an experienced manufacturer. Mr. Damon explained:

> The General Electric 7HA.02 advanced class gas turbines selected by DTE Electric follow a lineage of gas turbines produced by the manufacturer dating back in excess of 50 years, with installed experience of approximately 7,000 gas turbines with over 300 million operating hours. With each progression to the next advanced gas turbine class, General Electric has built upon technology used in earlier model gas turbines. In addition, it is noted that with each advancement in gas turbine technology, reliability and availability data has been maintained at a consistently high level. The advanced gas turbine commercial fleet has over 68,000 operating

> hours and the fleet leader has achieved rates of availability at 97.8% and reliability at 99.7%. This exceeds the publicly available Generating Availability Data System (GADS) publication by North American Electric Reliability Corporation (NERC) for operating combined cycle plants.

5 Tr 1482-1483.

The Commission finds that a smaller plant was not shown to be as economical as the 1,100 MW size, and there are limitations on the size options for the combined cycle technology, as Mr. Banks pointed out. A CT was also not as cost-effective compared to the proposed plant given the significant need for energy and capacity. Therefore, the option of a smaller plant was dismissed. And given the substantial near-term need to replace retiring coal plants, and the consideration of the expected feasibility, cost, and performance of alternative options presented in this case as discussed further below, the Commission finds, based on the evidence in this proceeding, that the technology and capacity of the proposed plant to be the most reasonable and prudent option.

The Commission agrees, however, with the Staff and other parties that DTE Electric's modeling approaches and interactions with the parties warrant attention. In particular, the Commission is concerned that constraints placed on the models by DTE Electric, such as limiting renewable energy to large blocks or pre-determining amounts of EE, and the utility's selection of optimal modeling runs limit transparency and the veracity of results. Such approaches, particularly if not well-documented and explained, can give the impression that modeling results were steered or forced into a pre-determined result. The Commission expects that an effective IRP should produce results, under certain scenarios, that show the preferred course of action is not actually the best option. This is how we know the IRP is testing the robustness of the preferred course of action by examining how it performs under various assumptions, even if those assumptions may seem unrealistic today.

The Commission expects DTE Electric to be more transparent and forthcoming with parties in its 2019 IRP, and the company would be well-served to prioritize such stakeholder engagement before it files its application with the Commission. The Commission also underscores the importance of risk analysis in the IRP, especially given the dynamic nature of the energy industry and emerging technologies. Accordingly, in preparation of the upcoming IRPs, the Commission intends to explore with the Staff to further examine risk assessment methodologies and best practices from other jurisdictions.

3. Projected Renewable Energy and Capacity Obtained under MCL 460.1028.

Ms. Schroeder explained that under Act 342, by 2021, DTE Electric is required to have a renewable energy credit portfolio equal to 15% of its sales, as calculated using the number of weather-normalized MWh of electricity sold by the electric provider during the previous year to retail customers in Michigan, or the average number of MWh of electricity sold by the electric provider annually during the previous three years to retail customers in Michigan. 8 Tr 2467, Exhibits A-20 and A-21.

Ms. Schroeder testified that DTE Electric currently has a nameplate capacity of approximately 996 MW of owned or contracted renewable energy generation comprised of wind, solar, biomass and landfill gas. This total amount includes 451 MW of company-owned wind, 458 MW of contracted wind, approximately 64 MW_{AC} of company-owned solar, 20 MW of contracted biomass, and 3 MW of contracted landfill gas. 8 Tr 2469-2471.

Ms. Schroeder explained that the Commission approved DTE Electric's renewable energy plan in Case No. U-18111, and the plan includes an additional 300 MW of wind and 25 MW_{AC} of solar resources. 8 Tr 2472. For the IRP 2017 Reference Case, DTE Electric assumed an additional 150 MW of wind and 25 MW_{AC} of solar above what was approved in Case No.

U-18111. 8 Tr 2472.

No party disputed that DTE Electric correctly reported the amount of renewable energy the company is required to provide under MCL 460.1028. Issues concerning cost and capacity assumptions, as well as modeling renewable energy, above the statutory mandate, are addressed below.

4. Projected Energy Efficiency Savings under MCL 460.1077.

Mr. Bilyeu provided an overview of DTE Electric's current EE programs, which are presently achieving 1.15% energy savings across all customer classes. No party disputed the amount of EE savings the company is required to achieve under MCL 460.1077. 7 Tr 2008. Issues concerning additional EE savings, above the 1% statutory mandate, are addressed below.

5. Projected Load Management and Demand Response Savings and the Projected Costs.

Mr. Kirchner provided an overview of DTE Electric's current DR programs which include residential, C&I, and pilot programs. Mr. Kirchner also provided the number of participants in each program, testifying that DTE Electric's DR program totals 572 MW of qualified resources. 7 Tr 2096-2097.

Mr. Kirchner testified that in the future, the company plans to invest in repairs to its interruptible air conditioning (IAC) program and, in 2017, will begin a programmable communicating thermostat (PCT) program for 10,000 residential customers. In addition, Mr. Kirchner indicated that DTE Electric will continue to explore other DR opportunities through pilot programs. 7 Tr 2098-2099.

For the IRP modeling in this case, Mr. Kirchner testified that in addition to the 572 MW of existing resources, DTE Electric plans to add 125 MW of DR through the IAC upgrade program. 7 Tr 2100, Exhibit A-31. Mr. Kirchner indicated that while other DR programs were modeled in the IRP, these programs were not selected. Mr. Kirchner concluded that the projected DR included in the 2017 Reference Case totals 572 MW of existing capacity in 2017 with projected growth of the DSM programs to 697 MW by 2021. 7 Tr 2100- 2101.

Issues and recommendations concerning additional DR are addressed below.

6. Analysis of the Availability and Costs of other Resources that could Defer, Displace, or Partially Displace the Proposed Project.

a. Integrated Resource Plan Assumptions

Various intervenors in the proceeding took issue with the company's assumptions about the market price for capacity, wind and solar costs and capacity, as well as DTE Electric's assumptions about future PURPA resources, additional renewable energy under MCL 460.1061, and battery storage. The issues, concerning modeling inputs rather than processes, are addressed in this subsection.

Mr. Fagan and Mr. Allison testified that DTE Electric overstated the market price for capacity in its modeling and questioned DTE Electric's limitation on capacity imports to 300 MW. According to Mr. Fagan, "these two aspects of the modeled representation of capacity imports are critical in order to properly include, in the assessment, the availability of less-expensive purchase capacity prior to turning to the capacity value provided by the proposed NGCC plant." 5 Tr 571. Mr. Fagan stated that correcting the price for capacity results in the deferral of the plant until at least 2026. 5 Tr 572.

Mr. Allison testified that DTE Electric relied on a capacity forecast developed by PACE, which in turn relied on forecasted reserve margins and net cost of new entry (CONE). 5 Tr 482-483. Mr. Allison stated that the PACE capacity price forecast is overstated because: (1) the forecast does not reflect historic PRA prices, which are 50%-125% lower than the PACE forecast; (2) DTE Electric has a history of forecasting higher-than-actual capacity prices as demonstrated in the company's PSCR plan and reconciliation filings; (3) there are expectations that resource adequacy in MISO will be sufficient; and (4) some of the assumptions in the PACE model were poorly supported. 5 Tr 484, 486, 487-488, 491-492.

In rebuttal, Ms. Wojtowicz explained that both Mr. Fagan and Mr. Allison largely base their criticisms on MISO PRA prices that are much lower than DTE Electric's forecast, although the PRA is irrelevant. Ms. Wojtowicz testified that under MCL 460.6w, the company is required to demonstrate capacity four years into the future, and the company cannot rely on the PRA to make this demonstration. Ms. Wojtowicz added that the PRA is capped at CONE for a CT and therefore does not reflect the cost of baseload generation that the company intends to retire and build. 7 Tr 2240. According to Ms. Wojtowicz, a more realistic comparison for capacity prices can be found in the results of a reverse capacity auction in summer 2017 for capacity purchases in 2018/2019 through 2022/2023. "Results of the Company's 2017 reverse capacity auction indicated steadily rising capacity prices throughout the next four years, culminating in an average offer price above $50k/MW-yr for the 2021/22 Planning Year." 7 Tr 2241. Ms. Wojtowicz added that even with the addition of the proposed project, the capacity resources in LRZ 7 are not expected to be sufficient to meet the LCR in 2023/24, thus placing upward pressure on the cost of capacity. 7 Tr 2241-2242, Exhibit A-55.

Ms. Schroeder testified that the 2017 Reference Scenario includes all wind and solar resources required to meet the mandate under 2008 PA 295 as amended by Act 342. 8 Tr 2472.
Ms. Schroeder further indicated that a High Renewables sensitivity that incorporates 1,500 MW of renewables above the Reference Case was modeled. According to Ms. Schroeder, consistent with the 35% goal outlined in Section 1 of Act 295, MCL 460.1001, the company expects that the combined renewable and EE portfolio in this IRP will meet the goal by 2025. 8 Tr 2473.

Ms. Schroeder testified that for cost assumptions associated with additional wind energy, DTE Electric used 2016 actual installed costs of $2,150 per kW, with costs declining based on estimates of future market costs. In addition, for all scenarios, DTE Electric assumed a net capacity factor (NCF) of 41%, cautioning that this is based on a wind farm in the most appropriate area for wind generation, and "wind parks developed through 2025 [are expected] to be located outside of the Thumb region, due to the Huron County voter referendum and local community resistance in the Thumb region." Thus, "future wind parks will likely have a lower NCF[.]" 8 Tr 2473-2474.

Ms. Schroeder testified that annual O&M and capital maintenance expenses, are estimated to be $16 and $20 per kW respectively and that these amounts are assumed to increase with inflation. With respect to the PTC, Ms. Schroeder explained that the 2018 wind park is assumed to receive 100% of the credit, and the 2020 wind park is assumed to receive 60% of the credit. 8 Tr 2474-2475.

For solar, Ms. Schroeder used 2016 actual installed costs of $1,900 per kW_{AC} as the baseline, and compared its internal forecasts, based on experience to date, with Navigant Consulting's utility scale forecast from its 2016 report, "U.S. Distributed Renewables Deployment Forecast." 8 Tr 2475. Exhibit A-23. Ms. Schroeder further testified that DTE Electric "expects future solar parks to operate at a 20% NCF_{AC} based on the Company's experience with fixed tilt ground mounted systems in Michigan." *Id.*

Ms. Hunt observed that although DTE Electric started its analysis of wind costs with the company's recent experience, several reliable sources report lower baseline costs for the Midwest. For example, Lawrence Berkeley National Laboratory (LBNL) reported an average installed cost for wind projects of $1,711 per kW for projects completed in 2016 in the Great Lakes Region, reporting that no project had a cost that exceeded $2,100 per kW installed. 5 Tr 632. In addition, the National Renewable Energy Laboratory (NREL) reported a national installed cost range of $1,737-$2,109 per kW, and EIA reported an average national installed cost for 2016 of $1,877 per kW. *Id.* Similarly, Ms. Hunt testified that DTE Electric's projected wind cost for 2018 of $1,828 per kW installed, was also relatively more expensive than other reported sources, as were the company's capital maintenance and O&M costs. According to Ms. Hunt, "Overall, market data suggest that, given expected O&M cost declines in the future, DTE Electric should consider reevaluating its O&M costs assumptions, including adding a de-escalation factor, similar to its installed cost assumptions." 5 Tr 634. Ms. Hunt testified that DTE Electric calculated a levelized cost of energy (LCOE) of $47 per MWh with the PTC and $70 per MWh without the credit. Again, Ms. Hunt pointed out that this was high in comparison to other sources.

Ms. Schroeder disagreed, noting that the company's basis for the Reference Cases' installed wind costs was a 2016 wind park that was competitively bid and audited by the Staff. For 2018 installed costs, the company again used a company project that had been competitively bid and audited. 8 Tr 2480. Ms. Schroeder reiterated that the company's 2020 wind project, which qualifies for 100% of the PTC, has an LCOE of $46 to $48, which is in line with the projection used in the models and consistent with other projections.

Mr. Lucas disputed DTE Electric's assumptions about solar technology. First, Mr. Lucas noted that DTE Electric used a 20-year life for new solar installations, explaining that although solar PPAs are often for 20 years, some solar panels have warranties of 25 years. 5 Tr 717. Next, Mr. Lucas testified that, in its Reference Case, the company used an annual panel degradation rate of 0.80%, which is higher than generally assumed. While DTE Electric updated the degradation rate to a more typical 0.50% in its 2017 Reference Case, Mr. Lucas pointed out that the company did the majority of its modeling using the 2016 Reference Case. 5 Tr 718. Mr. Lucas testified that accurate assumptions about panel life and panel degradation are a critical aspect of calculating solar costs, observing that increasing panel life and decreasing degradation are an important focus in the solar panel industry today. *Id.*

Mr. Lucas also questioned DTE Electric's assumption that only south-facing, fixed-tilt systems would be installed, testifying that the company is proposing the new plant to supply both energy and capacity. Mr. Lucas testified that while south-facing systems maximize the amount of energy production from solar, much higher capacity, as well as more energy, can be attained through the installation of single axis tracking systems. 5 Tr 720-721. Mr. Lucas indicated information from the FERC that shows the rapid adoption of single-axis tracking systems. 5 Tr 721.

Using Michigan-specific information, Mr. Lucas modeled several different solar systems, including single axis and double axis tracking. "Among fixed-tilt systems, south-facing was the worst choice for DTE's capacity needs. While this orientation did produce more energy than southwest or west-facing fixed-tilt systems, it contributed much less capacity." 5 Tr 723.

Mr. Allison testified that DTE Electric used different assumptions for solar capital costs at different points in its testimony, workpapers, and modeling. Mr. Allison pointed to a discrepancy between the amounts for solar installed costs in Exhibit A-23 and Mr. Chreston's workpapers containing solar cost assumptions. 5 Tr 455. While Mr. Allison agreed with DTE Electric's use of an "aggressive" cost decrease assumption for solar, he provided a graph that shows that the company's near-term solar costs are 24% higher than those forecasted by NREL, thus biasing its analysis against near-term selection of solar resources. 5 Tr 455-456. Mr. Allison also pointed to inconsistencies between Ms. Schroeder's testimony about O&M costs and the much higher O&M costs used in the modeling scenarios. 5 Tr 457. Mr. Allison testified that although DTE Electric corrected the error, he was not aware that the company re-ran any of the models with the corrected O&M amount. 5 Tr 458.

Mr. Allison echoed Mr. Lucas' concerns about DTE Electric's assumed capacity factor of 41% for new solar facilities, despite MISO's use of a default capacity credit of 50% for new solar. Mr. Allison testified that the use of the lower capacity factor failed to take into account solar technology improvements, and that it was based on the performance of just one of the company's solar installations. Mr. Allison opined that it is not appropriate to make projections on the basis of the performance of a single project and that the MISO default is based on a class average. 5 Tr 459-460.

In rebuttal, Ms. Schroeder testified that the company's installed cost for solar was a reasonable starting point for the projection, and that the company's "aggressive" cost-reduction scenario was in fact the most aggressive forecast available at the time the modeling was performed. Ms. Schroeder pointed out that the sources cited by Mr. Allison were only recently published.

Mr. Jester testified that DTE Electric's assumption that no additional renewable energy will be required under the customer-requested green energy provisions of MCL 460.1061 is erroneous. According to Mr. Jester, customer demand for additional renewable power is growing nationally and should be expected to increase in Michigan as well. Mr. Jester also contended that DTE Electric's failure to include new and existing PURPA contracts in its analysis was unreasonable, noting that DTE Electric's modeling assumed that existing PURPA contracts will begin to expire in 2024 and will not be renewed. Mr. Jester also pointed to significant interest in new PURPA development as a result of DTE Electric's avoided cost proceeding in Case No. U-18091.

In rebuttal, Mr. Bloch testified that it was unreasonable to expect expiring PURPA contracts to be renewed, noting that 95% of DTE Electric's 104 MW PURPA contract portfolio includes landfill gas and municipal solid waste, energy sources that may no longer be available when the contracts expire. 8 Tr 2348. In addition, Mr. Bloch pointed out that the company's PURPA avoided cost case is still pending and that the company disputes the method for establishing avoided cost rates. 8 Tr 2350-2351.

Mr. Jacobs provided an overview of commercially available battery storage resources that are being cost-effectively deployed around the country. Mr. Jacobs opined that although DTE Electric considered battery storage in its IRP, the company dismissed this option without sufficient justification. 5 Tr 879-880.

Mr. Jacobs highlighted the benefits of battery storage, including rapid incremental development, flexibility, grid services (i.e., congestion relief) and ancillary services such as frequency regulation. Mr. Jacobs added that the value of ancillary services is recognized in the market. 5 Tr 880-881.

Mr. Jacobs testified that the cost of battery storage is projected to decline significantly over the next five years as reported in the Lazard annual Levelized Cost of Storage reports. According to Mr. Jacobs, these reports for 2015, 2016, and 2017 project cumulative cost reductions for lithium-ion battery systems of 47%, 38%, and 36% respectively. Other projections from Bloomberg, Navigant, and Greentech Media project similar cost reductions. 5 Tr 883-884.

Mr. Jacobs testified that several other utilities in the United States have updated their IRPs to include battery storage as a resource option, noting that Indiana Power and Light's base IRP calls for an increase of 500 MW in storage capability; Arizona Public Service added a similar amount to its IRP; Portland General Electric is proposing to add at least 5 MW-hours of storage; and Public Service Co. of New Mexico is issuing an RFP for new storage, renewables and flexible natural gas. 5 Tr 887.

Mr. Jacobs testified that although DTE Electric initially considered battery storage as an option, the technology did not pass the first screen and thus was not selected for further evaluation. Mr. Jacobs opined that DTE Electric's assumptions about the future cost decline of storage likely led to this result. According to Mr. Jacobs, DTE Electric assumed battery costs would decrease by 26% over 5 years, a significantly lower decline (and therefore higher storage cost) than is seen in other projections. 5 Tr 889. Mr. Jacobs also pointed out that DTE Electric's Strategist modeling did not include the ancillary service and flexibility values associated with storage. Thus, Mr. Jacobs testified that DTE Electric undervalued battery storage by failing to include a reasonable analysis of the benefits of this technology. 5 Tr 895.

In rebuttal, Mr. Chreston testified that while some utilities have included storage as a resource in their IRPs, most have other compelling reasons to do so, including significant renewable energy additions, transmission benefits, or policy mandates. Mr. Chreston added that of the utilities Mr. Jacobs cites, most do not plan to add storage until the mid-2020s or later. 6 Tr 1803-1804. Mr. Chreston further testified that the company's assumptions about the declining cost of storage were reasonable at the time they were made; however, "[w]hile batteries are still a high cost resource relative to other options, as technologies continue to improve and costs decline, the Company will continue to evaluate their potential role in our portfolio." 6 Tr 1805.

Discussion

The Commission finds DTE Electric's modeling assumptions to be reasonable for the portion of the IRP that addresses the timeframe in which the plant will be built (i.e., until 2022). First, with respect to capacity costs, the Commission agrees with the company, that use of the MISO PRA as a comparison to capacity cost is inappropriate. The PRA functions as a balancing market for small capacity purchases and therefore does not approximate the needs that the company will have with the Tier 2 unit retirements. In addition, as DTE Electric points out, under MCL 460.6w, the company is required to demonstrate capacity four years into the future, and that cannot be accomplished using the PRA. Therefore, the Commission finds DTE Electric's capacity cost assumption, based on the company's 2016 reverse capacity auction is reasonable.

With respect to wind resources, the Commission agrees with DTE Electric that basing its projection of the future cost of wind energy on the company's most recent wind farm costs resulted in costs that are only slightly above the high end of the range of wind energy installed costs that Ms. Hunt reported. Moreover, as DTE Electric points out, although the company assumed a 41% capacity factor based on Huron County production, local siting restrictions have prevented new wind energy developments in this optimal wind zone, and future wind parks, located outside this area, may not achieve capacity levels as high as 41%. Thus, DTE Electric's perhaps optimistic assumption about net capacity, to some degree, offsets the company's higher assumed costs. The Commission also finds that DTE Electric's LCOE with and without the PTC are near, or within, the ranges that Ms. Hunt reported for comparison purposes.

Similarly, for installed solar costs, the Commission finds the company's use of its own installed solar costs, and projection of future costs, to be reasonable. DTE Electric plausibly based its projection on the company's own experience including actual operational experience with solar tracking systems in Michigan's climate. In addition, DTE Electric used several credible sources to inform its solar cost projections. Moreover, in light of rapid cost reductions in solar technology, the company states that it intends to undertake further evaluation of the technology.

With respect to assumptions about additional renewable generation resulting from customer-requested green energy under MCL 460.1061, the Commission agrees with the company that Mr. Jester's projection is overly optimistic. Given the difficulty in making predictions of customer interest, the Commission does not believe it is prudent to plan on a significant increase in Section 61 renewable energy between now and 2022, because these programs are still under development, with Commission decisions expected in the fall of 2018. Nevertheless, the Commission expects additional information about customer interest in this optional program may be available by DTE Electric's 2019 IRP filing, where this assumption can be further tested. DTE Electric also included 300 MW of wind energy for green pricing programs in its recently filed renewable energy plan in Case No. U-18232.

The Commission agrees ELPC *et al.*, Ann Arbor and EIBC, that DTE Electric did not provide strong support for its assumption that current PURPA contracts will not be renewed; the Commission finds this assumption to be inappropriate as a matter of policy but nevertheless notes that most of DTE Electric's PURPA contracts are not set to expire until after the company completes its 2019 IRP and that they represent a relatively small amount of energy and capacity. By the 2019 IRP filing, changes, if any, to PURPA should be known and addressed in that proceeding. If there are no changes, the Commission agrees with ELPC, *et al.* that the appropriate assumption is that the law will continue as it currently is and that the contracts will be renewed.

With respect to new PURPA contracts, the Commission agrees with Mr. Jester's observation that:

> The interplay between PURPA avoided cost proceedings and consideration of utility proposals for Certificates of Necessity or through Integrated Resource Planning raises the potential for conflict, requiring careful consideration in all relevant proceedings, including this one. If the utility states in its PURPA proceedings that it does not forecast capacity needs from PURPA qualifying facilities because it has plans to acquire non-PURPA capacity, while at the same time the utility states in a Certificate of Necessity proceeding that it does not forecast PURPA resources in its integrated resource planning and therefore must build other resources, were the Commission to accept both statements, this may result in sanctioned discrimination by the utility against PURPA qualifying facilities and fully undermined PURPA's intent.

5 Tr 431-432.

Exhibit ELP-65 contains a notification from DTE Energy to potential QFs that the utility does not have a need for capacity over the next ten years. The Commission finds that it is inappropriate for DTE Electric to publish such a statement without a determination from the Commission that the utility, in fact, does not have a capacity need over the next 10 years. DTE Electric's actions are especially troubling given the utility's obligations under PURPA, the capacity need determinations by the Commission in DTE Electric's pending PURPA case, Case No. U-18091, and the information in this docket filed by the company identifying a near-term need incremental to the proposed gas plant. Ms. Dimitry testified that the Company's expected resource requirements for energy and capacity would most prudently be addressed by the proposed 1,100 MW NGCC, with DR and minor market purchases or other resources up to 300 MW being used to make up any remaining energy and capacity needs. 6 Tr 1609. Mr. Chreston further elaborates on the remaining 300 MW capacity need, testifying that "[e]ven though the modeling assumes that the amount would be filled by market purchases, it should be thought of as an open position that can be filled by smaller economic resources determined at a later date. These resources could consist of a portfolio of renewables, CHP, DG, or demand response options in addition to market purchases." 6 Tr 1742-1743.

The Commission acknowledges that potential benefits may exist to remain flexible and determine specific plans for the remaining capacity need at a later date, and the Commission expects that DTE Electric has every intention of filling the remaining capacity need with resources at an appropriate point in the future. However, DTE Electric's intentions to fill that capacity need at some future date do not alleviate the company's obligations under PURPA. Therefore, the Commission finds that absent action by DTE Electric to address its plans for meeting its capacity needs over the 10-year horizon and make associated commitments through applicable regulatory filings, the Commission's determination of need in this proceeding, based on DTE's evidence with a near-term need of 300 MW in the early 2020s, serves as the Commission's current determination of the company's capacity need over the 10-year period.[12] The Commission notes that it may further explore issues surrounding how capacity determinations are made for purposes of PURPA in U-20095, rulemakings or other proceedings.

Finally, with respect to battery storage, the Commission is not inclined to write off this emerging technology as lightly as DTE Electric, who dismisses storage with, "this is not Shark Tank" in its reply brief, p. 70. Nevertheless, the Commission finds persuasive the company's testimony that the utilities that are planning the addition of utility-scale storage are not intending to do so until the mid-2020s or later. In its 2019 IRP, DTE Electric is expected to include a better evaluation of storage options, including a quantification of storage benefits including flexibility, grid support, and ancillary services as outlined in Mr. Jacobs' testimony.

b. Integrated Resource Plan Scenarios, Sensitivity Analyses, and Results

Once IRP assumptions are established, as discussed above, the next step is to model various scenarios and sensitivity analyses. Mr. Chreston testified that the purpose of an IRP is to determine if additional resources are required to meet the energy and capacity needs of the utility's customers and, if so, additional analyses are undertaken to determine the most reasonable and prudent means to meet those needs. 6 Tr 1712. Mr. Chreston identified the steps taken in the modeling process as: (1) evaluating the company's capacity position; (2) determining alternative resource options; (3) developing model assumptions including scenarios and sensitivity analyses;

[12] DTE Electric's analysis includes the assumed retirement of Belle River Unit 1 on May 31, 2029 and Belle River Unit 2 on May 31, 2030. 6 Tr 1730

(4) modeling and analyzing results; (5) assessing other considerations; (6) undertaking a risk analysis; and (7) identifying the proposed course of action. 6 Tr 1712-1713.

Mr. Chreston testified that in determining resource alternatives to address capacity needs, the company evaluated several technologies including natural gas, coal, nuclear, renewables and demand side management resources. For each option, the company calculated the levelized cost of energy (LCOE), and eliminated options with the highest LCOE. The remaining technologies that were evaluated further were natural gas CT, NGCC, renewables (wind and solar), EE, DR, storage, customer-owned generation, transmission, distribution efficiency, and short-term market purchases of 300 MW based on import limits and capacity availability in MISO. 6 Tr 1721-28; Exhibit A-4 2nd Revised, Table 10.10-1. Mr. Chreston added that the company also considered a no-build option, but determined that even under the most aggressive EE and DR programs "the retiring coal capacity would still leave a shortfall of approximately 900 MW by 2023." 6 Tr 1724.

Mr. Chreston explained that the company modeled both scenarios and sensitivities and that "[s]cenarios are futures that affect market and commodity prices on a broad basis[,] which include, "assumptions pertaining to Environmental legislation, commodity supply and demand, new resource capital costs and existing unit retirements[.]" 6 Tr 1733. On the other hand, sensitivities "are more Company specific variables that only affect the DTE Electric service territory and/or Michigan." 6 Tr 1733-1734.

Mr. Chreston testified that the modeling looked at five scenarios: Reference Case, High Gas Prices, Low Gas Prices, Emerging Technology, and Aggressive CO_2. The company also modeled eight different sensitivities including high and low load growth, higher renewable energy mandate, EE, higher NGCC capital costs, NGCC size, electric choice return, CO_2 reduction, and a new nuclear plant. 6 Tr 1734-1737. Mr. Chreston noted that not every sensitivity was run on every scenario, however most were run on the Reference Case, because that was considered the most likely future scenario. Mr. Chreston indicated that in the end, over 50 different model runs were completed using various combinations of assumptions. 6 Tr 1737-1738. Mr. Chreston added that after new energy legislation was enacted in 2016, a 2017 Reference Case was developed containing updated assumptions for market prices, load forecast, fuel prices, EE and Renewables. The 2017 Reference Case did not change the prior outcome that showed that a 1,100 MW NGCC should be added. 6 Tr 1739, Exhibit A-4, 2nd Revised, Section 12.2.

Mr. Chreston explained how various load, fuel, and market price assumptions were developed, testifying that for capacity prices, the company used market forecasts developed by PACE. Mr. Chreston testified:

> After the energy market is determined, net CONE is calculated for a CCGT unit. Net CONE is the "Cost of new entry" less the energy margins. The amount of reserve margin in zone 7 is also determined for each scenario. If the reserve margin is low, then the capacity price is set closer to the net CONE value. If there is sufficient capacity built in the zone, the capacity price is a fraction of the net CONE price.

6 Tr 1741.

Mr. Chreston reiterated that up to 300 MW of capacity purchases were allowed in any year in the various scenarios and sensitivities, noting, "Even though the modeling assumes that the amount would be filled by market purchases, it should be thought of as an open position that can be filled by smaller economic resources determined at a later date. These resources could consist of a portfolio of renewables, [combined heat and power] CHP, DG, or demand response options in addition to market purchases." 6 Tr 1742-1743.

Mr. Chreston described the process and results of the company's modeling, explaining that:

> [A]ll technologies that were determined to be commercially viable and technically feasible were evaluated through LCOE analysis and Market Valuation. Once the least economic technologies and resources were screened out, the remaining

> resources were put into the Strategist® optimization, resulting in the selection of resource plans for each scenario and sensitivity.

6 Tr 1746. Additional factors were also considered in determining the resource plan including "reliability, affordability, clean, flexible and balanced, compliant and reasonable risk." 7 Tr 1747.

Mr. Chreston testified that the selected plan under the Reference Case includes 100 MW of incremental solar by 2021; 150 MW of incremental demand response program expansion by 2021; 1,100 MW NGCC plants in 2022 and 2029, 500 MW of additional wind by 2025, and 1.50% EE savings. 6 Tr 1752.

Mr. Chreston testified that the 1.5% EE savings level was the most cost-effective level on an NPV basis, and had the highest benefit cost ratio. Under all scenarios and thirty sensitivities, the optimum level of EE was 1.5% and two NGCC plants were selected for 2022 and 2029. 6 Tr 1753-1756, Exhibit A-8.

Mr. Chreston stated that although the Strategist modeling was largely based on modeling constraints and quantitative inputs, "The other factors of Clean, Flexible and Balanced, and Reasonable Risk must either be handled more qualitatively outside the Strategist® model or by using techniques that quantify these in a way that rates alternative portfolios against each other based on how they perform[.] 7 Tr 1757. Mr. Chreston explained that the risk analysis was a four-part inquiry:

> The first was a Stochastic analysis, which focused on maintaining or minimizing the "Reasonable Risk" principle. The second was an Analytic Hierarchy Process (AHP) analysis. The AHP analysis quantified and optimized the principles of affordability, clean, flexible and balanced, and reasonable risk. The third part was a refresh of our Reference scenario (i.e., 2017 Reference scenario) with the latest assumptions available since the modeling assumptions from the five scenarios had originally been locked in as of June 2016. Lastly, we completed a Change analysis that considers how adaptable the plan is to new inputs and changes to the assumptions.

6 Tr 1757-1758.

Mr. Chreston explained the Stochastic, AHP, and Change analyses, as well as the Reference update. 7 Tr 1758-1767. Mr. Chreston testified that under the Change analysis risk review:

> In the high load and both choice return sensitivities, additional resources are needed, and CC technology is still selected. In the low load and the 2% EE sensitivities, the CC technology is still selected, however it is delayed one year. If future signposts indicate that the load is higher than forecast or choice load is known to be returning, then the increased need for capacity can be mitigated by issuing a RFP for added capacity to bridge until the next IRP is completed. Similarly, if sales are lower than forecasted, then economic analysis could be done to determine the value in delaying the Proposed Project one year. The value of the delay would be offset by the risk of the remaining tier 2 coal units needing to retire earlier than 2023 and potential EPC cost increase.

7 Tr 1767. Mr. Chreston concluded that overall, the risk analyses "support that the proposed plan is economic under a variety of situations, and is robust and prudent." *Id.*, Exhibit A-6 and Exhibit A-10 3rd Revised.

Finally, Mr. Chreston provided the calculation of the revenue requirement for the project including rate base, O&M costs, and net PSCR impact compared to a no-build option. Mr. Chreston testified that the result of the comparison showed a benefit to customers of approximately $33 million in the first operating year of the plant. 6 Tr 1770, Exhibit A-9.

Ms. Gould testified that DTE Electric modeled "planned" renewables, energy efficiency and DR in its IRP, opining that the use of the word "planned" indicates that "the levels of these energy resources were calculated prior to inputting them into the modelling." 5 Tr 242-243. Ms. Gould explained that by considering energy efficiency a demand-side resource rather than a supply-side resource, EE was never maximized as an alternative to the proposed project. Ms. Gould further testified that DTE Electric failed to adequately evaluate EE savings above 1.5%, noting that the difference in the NPV between 1.5% and 2% energy efficiency savings is minimal and that certain savings, such as reduced fuel imports and lower CO_2 emissions, are not fully captured in the analysis. In addition, DTE Electric did not include more EE in its high gas price scenario, even though savings would be greater. 5 Tr 244.

Ms. Gould testified that the updated Michigan Lower Peninsula Electric Energy Efficiency Potential Study determined that DTE could meet an EE savings target of 2% through 2026 or longer. 5 Tr 245, Exhibit S-3.2. Ms. Gould admitted that 2016 PA 342 requires EE savings of 1%, however, the company receives a financial award if it achieves savings of an additional 0.50%. Ms. Gould testified that the Staff fully supports an EE savings level of 2% in DTE Electric's IRP, disputing the company's claim that ramping up from 1.5% to 2% would be administratively burdensome and difficult for vendors. She further testified that Mr. Bilyeu's testimony shows that over 20 years, the cost for 2% energy efficiency savings is less than the cost for 1.5% energy savings over the same time period. Ms. Gould also highlighted the minimal difference in the UCT scores for 1.5% versus 2.0% savings. 5 Tr 249-250.

Ms. Gould admitted that EE savings could not substitute for the full amount of the company's capacity need, "but even nominal increases of EWR provide security and stability for the Company in meeting the energy needs of their customers." 5 Tr 252. Ms. Gould therefore recommended that the Commission condition approval of the CONs on a requirement that DTE Electric implement 2% EE savings.

Mr. Neme similarly took issue with DTE Electric's assumptions about achievable EE savings between now and 2030 are far too conservative, and that a more aggressive EE strategy could defer the proposed NGCC plant until 2030 with significant customer savings. Mr. Neme pointed out that the EE potential study on which the company relied only looked at EE potential based on the current incentive levels the company provides under its programs. 5 Tr 380. Thus, Mr. Neme testified that the study, like most potential studies, does not reflect the significantly larger amount of EE that is cost-effectively achievable. 5 Tr 381. Mr. Neme pointed to Massachusetts which he testified is one of the few states where utilities are attempting to capture all cost-effective EE savings. 5 Tr 382-383.

Mr. Neme explained that there are a number of reasons why EE potential studies result in conservative estimates of energy savings including a focus on known measures while excluding emerging technologies, a failure to capture savings from "custom" measures that are unique to a single site or industry, a failure to account for increased savings or decreased costs of particular measures over time, and placing artificial limitations on the amount of financial incentive that can be offered for adoption of EE measures. 5 Tr 384-386.

Mr. Neme pointed out that DTE Electric's most aggressive EE scenario (2% EE savings) still produced a very high benefit cost ratio of 7.95, observing, "with a benefit-cost ratio of almost 8 to 1, the Company could have doubled its assumed financial incentive levels for every efficiency measure – with related increases in program participation and savings levels – and still saved at least four dollars in avoided energy supply costs for every dollar spent." 5 Tr 387-388.

In rebuttal, Mr. Bilyeu testified that Ms. Gould's 2% EE proposal is inappropriate because the company has demonstrated that 1.5% EE is most reasonable and most likely to deliver the projected energy savings; the company already has an approved plan for 2018-2019; and DTE Electric will be filing another IRP in March 2019.

In response to Mr. Neme, Mr. Bilyeu testified that an incentive level of 50% of measure cost is reasonable based on its own and other EE potential studies, and that the higher incentive payments that Mr. Neme suggests are unnecessary to achieve higher savings. 7 Tr 2029.
Mr. Bilyeu reiterated that DTE Electric's focus was on achieving aggressive levels of EE savings while remaining cost-effective, as evidenced by the American Council for an

Energy-Efficient Economy (ACEEE) 2017 Utility Energy Efficiency Scorecard, which compared DTE Electric to 52 other utilities. 7 Tr 2031.

Ms. Smith outlined DTE Electric's current DR program, focusing specifically on the company's interruptible air conditioning program (IAC). Ms. Smith explained that DTE Electric is planning to add 125 MW to its DR portfolio through repairing switches in its existing IAC program. Ms. Smith questioned DTE Electric's explanation that the IAC program is capped in the company's tariff, noting that the limit on participation is self-imposed. Ms. Smith pointed out that she was unaware of any cost-of-service reason to cap IAC program participation. 5 Tr 257-258.

Ms. Smith disputed DTE Electric's claim that its proposed DR program was in line with the company's most recent potential study, observing that the potential study projects achievable DR of 825 MW by 2020, whereas the company only plans to attain 697 MW by 2021. Moreover, the State of Michigan Demand Response Potential Study identified 991MW of DR potential by 2020, which would be 386 MW over the company's baseline. 5 Tr 259-260. Ms. Smith summarized:

> The Company can improve and expand their existing DR programs in a cost-effective manner. Further, Staff believes the Company did not fully assess for modelling purposes of this certificate of need filing that DR in conjunction with Energy Waste Reduction and Renewable Energy could provide a cost-effective solution to reducing the size of a gas plant needed to fill capacity shortfalls, and could delay a construction start date, all while enhancing distribution reliability and stability in their service territory and should be considered in the Company's IRP as a packaged resource which competes with other generation resources.

5 Tr 261.

Mr. Jester testified that, with respect to DR, DTE Electric "omits the lowest-cost and largest opportunities for additional demand response[,]" observing that the Statewide Demand Response Study from 2017 shows much higher potential for DR than the study that the company relies upon. 5 Tr 420-421. Exhibit MEC-42. Mr. Jester points out that the "Low Realistic Potential" in the statewide study shows a much higher DR potential than the company assumes. "At a minimum, for the purposes of DTE's current plan, the Low Realistic Potential in the Commission's study should be considered as available resources for a "most reasonable and prudent" plan, followed by consideration of the implementation of additional efforts[.]" 5 Tr 421. The Low Realistic Potential considers 10 existing and new programs and results in additional DR of 265 MW in 2018 escalating to 1,339 MW in 2037. 5 Tr 422, Table 5-10.

With respect to the costs of DR, Mr. Jester testified that although DTE Electric evaluated a number of DR programs in its IRP, the company failed to consider programs that are considered least-cost options, such as real time pricing, time-of-use (TOU) rates, and variable peak pricing. 5 Tr 423, Table 5-5. Mr. Jester stated that based on his recommendations, DTE could have available an additional 335 MW of DR in 2023. 5 Tr 424.

Mr. Jester testified that he included two sets of DR assumptions to Mr. Evans: a High Realistic Potential DR and a Low Realistic Potential DR. 5 Tr 426. Exhibit MEC-46. By inputting the Low Realistic Potential DR to the model, Mr. Evans was able to demonstrate that the plant could be delayed until 2023.

Mr. DiDomenico pointed out that DTE Electric should have included an additional 138 MW of UCAP in its 2017 reference case to reflect the company's planned investments in PCT and other new DR programs.

Mr. Kirchner responded that the new programs were modeled in the 2017 Reference Case but were not selected. 7 Tr 2107. Mr. Kirchner further pointed out that unlike EE programs, DR programs require regulatory approval and cost recovery through rate cases. 7 Tr 2107-2108. In response to Ms. Smith, Mr. Kirchner testified that DTE Electric has not "capped" the IAC program, but the company does not expect more customer participation given the availability of alternatives like the PCT program. 7 Tr 2108.

In response to Mr. Jester, Mr. Kirchner stated that the statewide potential study assumes that 450,000 DTE Electric customers will sign up for TOU rates in the next four years, a completely unrealistic assumption. The statewide study further assumes that DTE Electric has 68 MW of direct load control hot water heating by 2023, even though only 0.5% of the company's sales forecast includes hot water. 7 Tr 2110.

Mr. Harlow testified that DTE Electric failed to analyze a high renewable energy (20%), high EE (2% by 2020) and DR at 5.8% of peak demand by 2023, despite Staff's request that the company do so. According to Mr. Harlow, such a model run could demonstrate that the proposed NGCC could be reduced in size or could be delayed economically. Mr. Harlow also suggested that the 2 MW and larger renewable projects in DTE Electric's interconnection queue could be used to increase the company's renewable portfolio at the company's avoided cost.

Ms. Simpson agreed that DTE Electric modeled a range of potential scenarios but she expressed concerns about the modeled size of some of the resources, which resulted in renewables and demand side resources treated unequally to conventional generation. According to Ms. Simpson:

> [I]n some instances resource expansion models can be influenced by the specified size of the new resources available for the model to select. For instance, smaller resources are less expensive but if there are not enough of them to fill the entire need, the model will select the larger, more expensive resource instead. Models do not typically overbuild unless they are forced to do so by the user. In this instance, the model may select the single large option that fills the entire need because the user did not offer enough smaller options to allow the model to diversify. If the model cannot solve the expansion plan using the limited number of smaller options, then it is forced to select the larger resource option as being the most economical.
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> * * *
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> One way to avoid such a situation is to model a generic combined cycle and a generic combustion turbine as smaller increments but allow the model to build multiple units in one year. This method allows for clear visibility around the actual amount of energy and capacity needed from larger generation options while still including any of the less expensive but smaller demand side options and additional

> renewable energy options that may be cost effective. In short, this method allows new resources to be selected on an equitable basis.

5 Tr 210. Ms. Simpson further observed:

> It is true that the Company's proposed larger single natural gas generation resource would have an advantage of economies of scale resulting in a lower per megawatt cost as compared to the same technology in a smaller size. However, without running a scenario with the energy efficiency, demand response, and renewable energy resources as Staff has indicated and utilizing the generic resource method discussed above, the total cost of all resources combined is unknown.

5 Tr 211.

With respect to the company's risk analysis, Ms. Simpson explained that DTE Electric evaluated four very different build plans, all containing the proposed project. According to Ms. Simpson, three of these plans "were not optimized generation plans or even near optimized expansion plans or any scenario in the Company's IRP. It is not clear exactly what the Company expected to determine from such a risk assessment." 5 Tr 213.

Mr. Evans testified "that DTE has not supported its application for approval of the new NGCC generation facility with the required analyses. Specifically, DTE has not accurately projected or analyzed resources, capacity and load requirements, and costs under its proposed portfolio." 5 Tr 322. Mr. Evans testified that in his modeling, he identified scenarios that could defer, displace, or partially displace DTE Electric's proposed plant until 2029, with a savings of $1.88 billion in net present value of revenue requirement (NPVRR) compared to the company's preferred plan. *Id.*

Mr. Evans described the Strategist model as follows:

> Strategist is a resource planning software model used to develop resource plans for electric utilities. Given projections of future load growth, fuel prices, the costs of potential new resources and other information, Strategist selects a resource plan that minimizes ratepayer costs while maintaining reliable service. Strategist proceeds one year at a time, simulating hourly dispatch while tracking generation and system costs. Strategist produces a schedule of various combinations of new resource additions, which may include natural gas combined cycle plants, combustion turbines, renewable resources, peak load reduction programs, and energy efficiency programs. Strategist tracks the cost for each combination, and at the end of the

> model run, identifies the least cost expansion plan as well as sub-optimal plans evaluated during the simulation. Thus, Strategist allows for the consideration, testing, and comparison of various scenarios under different sensitivities (e.g., future fuel prices).

5 Tr 323. Mr. Evans testified that the first step in his analysis was to recreate the model exactly as DTE Electric did, using the same inputs and assumptions in order to replicate the company's output. In this step, Mr. Evans reported that he found discrepancies between what the company reported as the modeling output in testimony and in the company's IRP for most of the Strategist runs. 5 Tr 324. Mr. Evans explained that Strategist produces a range of plans, from most to least optimal, it appeared that DTE Electric manually chose a non-optimal plan in many of its runs. For example, Mr. Evans pointed out that for its 2% EE plan, the company chose the 22nd ranked plan rather than a plan that ranked higher. 5 Tr 324-325. Mr. Evans explained that once he received information from the company about which plans had been selected, he was able to "benchmark" DTE Electric's Strategist results. 5 Tr 326.

Mr. Evans stated that the significance of DTE Electric's choice to select sub-optimal plans means that some resource scenarios are not necessarily the least-cost plan. "Moreover, the comparisons DTE made among the various Strategist cases inappropriately compare the least cost plan for one case to plans that are, in many cases, not the least-cost plan, and thus are meaningless comparisons." 5 TR 327. For example, "DTE chose . . . the second-best plan for its Base Resource case, the second-best plan for its Preferred case (the 1.5% Energy Efficiency case), and the twenty-second-best plan for its 2.0% Energy Efficiency case. The resulting comparisons between different cases and scenarios are skewed by this manual selection of non-optimal plans." *Id.* Mr. Evans stated that he corrected DTE Electric's inaccurate comparisons and found that there are more savings from the optimal 2% EE plan than the 1.5% EE plan that the company favors. *Id.*

Mr. Evans acknowledged that "[o]nce a utility has identified and reviewed all optimal model results and sensitivities, an evaluation of whether other considerations (such as minimizing risk) justify selecting a plan that is not least-cost may occur." However, Mr. Evans testified that DTE Electric failed to disclose what other considerations led the company to select and compare non-optimal plans. 5 Tr 328.

Mr. Evans listed several input errors that he found in DTE Electric's modeling, including (1) failure to include additional DR until after 2023, thereby keeping additional DR from competing with the proposed project; (2) incorrect modeling of EE programs, which assumed that EE savings will only last 15 years; (3) incorrect capacity credit for solar resources, which assumed only a 41% on-peak capacity credit; (4) failure to consider and add incremental amounts of renewable energy, wherein DTE Electric's modeling only allowed the selection of 502 MW increments of solar and 1,000 MW increments of wind; and (5) incorrect costs for wind and solar resources. 5 Tr 329-335. In addition, Mr. Evans testified that he removed O&M from solar and wind capital costs. 5 Tr 336. Mr. Evans presented Exhibit MEC-12, Case MEC 0, which Mr. Evans testified corrected the errors in DTE Electric's 1.5% EE run, resulting in a delay in the plant until 2029 with a savings of $1.882 billion NPVRR.

Mr. Evans testified that DTE Electric's 2017 Reference Case update also contained errors concerning the heat rate of the proposed NGCC and the Belle River peakers, resulting in a significantly understated cost for the proposed plant. 5 Tr 336-337. Mr. Evans testified that based on corrections to DTE Electric's inputs and assumptions and inputs from other witnesses to the case, he undertook several additional Strategist model runs. Mr. Evans presented Table 1 in his testimony, which demonstrates the results of 11 model runs. 5 Tr 340-342. Mr. Evans also described the inputs and adjustments made in each of the runs. *Id.* Mr. Evans concluded that:

> Strategist runs based on DTE's modeling but correcting DTE's flaws and properly considering all resources show that DTE has more cost-effective options available to meet the identified need for capacity in 2022. In fact, correcting these DTE Strategist flaws delays the need for DTE's proposed NGCC plant until 2029 and results in $1.882 billion (NPV) in cost savings. In addition, further Strategist modeling shows that there are many scenarios that would also delay the need for the proposed NGCC plant and provide significant savings to ratepayers, compared to DTE's proposed 1,100 NGCC generating facility in 2022.

5 Tr 343.

Mr. Evans filed supplemental testimony addressing errors that DTE Electric acknowledged making in the Strategist runs for the 2017 Reference Case that was submitted with the company's application. 5 Tr 346, Exhibit MEC-109, MEC-110C and MEC-111C. Mr. Evans testified that the company's error in the heat rate of the plant increased the cost of the proposed NGCC and decreased the generation of the plant. 5 Tr 347-348. Despite correcting these errors, DTE Electric made no adjustments to its proposed plan. 5 Tr 349.

In rebuttal, Mr. Chreston testified that the alternative analyses provided by Mr. Evans and Mr. Beach "are based on a misrepresentation of modeling results that stem from failing to compare DTE Electric's Proposed Project on an equivalent basis." 6 Tr 1777. Mr. Chreston explained that Mr. Evans adjusted O&M costs for wind and solar so that they were not treated as capital costs. However, the same adjustment was not made for the O&M costs for the proposed project, thus making the project appear more expensive. In addition, Mr. Chreston testified that Mr. Evan's corrections were made to the 2017 Reference Case but included a generic NGCC as a resource option rather than the proposed project. 6 Tr 1777-1778.

Mr. Chreston testified that using Mr. Evan's Case 0 as a starting point, he revised the treatment of O&M costs and introduced the proposed NGCC as an option. EE and DR levels were not altered. *Id.* The results of Mr. Chreston's re-analysis of Mr. Evans' Case 0 showed, based on different adjustments: (1) a generic 3x1 NGCC in 2023 at a cost (NPVRR) that is $44 million more than Mr. Evan's Case 0; (2) a generic NGCC in 2023 at an NPVRR that is $78 million less than Mr. Evans' Case 0; (3) the proposed plant in 2023 at a cost (NPVRR) that is $545 million less than Mr. Evans' Case 0. 6 Tr 1779-1780.

Mr. Chreston testified that the reason the plant is moved to 2023 is because he did not modify the EE assumptions by Mr. Neme "the result of which incorrectly moves the need for capacity to 2023." 6 Tr 1780. Mr. Chreston also explained that the heat rate errors that Mr. Evans cited in his supplemental testimony do not affect the outcome of the modeling, noting that the majority of the scenarios and sensitivities assumed the correct heat rate. The two modeling runs where incorrect heat rates were used were rerun with correct inputs, and the result, a 1,100 MW NGCC in 2022, was the same. 6 Tr 1782.

Mr. Chreston disputed Mr. Evans' claim that the heat rate error calls into question DTE Electric's entire analysis, reiterating that the company's case included 60 different model runs, only two of which contained errors in heat rate. 6 Tr 1783. In addition, Mr. Chreston disputed that the company failed to detect a $500 million error, explaining that changes in NPVRR only "come into play when comparing that run against a sensitivity. However, the 2017 IRP reference case Strategist run did not compare the total net present value of that plan against another sensitivity." 6 Tr 1784.

With respect to Mr. Evans' claim that MEC/NRDC/SC's preferred case, Case 0, results in a $1.88 billion NPVRR cost savings, Mr. Chreston testified that Mr. Evans "draws his conclusion by making a flawed comparison between his Case 0 and DTE Electric's 2016 1.5% EE case." 6 Tr 1785. Mr. Chreston explained:

> Case 0 that is being proposed as the recommended course of action by Witness Evans is modeled on a different basis than DTE Electric's 2016 1.5% EE case. MEC Witness Mr. Neme further claims that "DTE significantly overstates the amount of future efficiency program savings embedded in its load forecast" (Neme

> testimony, p 7), and makes an adjustment to MEC's Case 0 to account for this assumption. This adjustment lowers the load forecast. However, Company Witness Mr. Leuker thoroughly refutes the appropriateness of Witness Neme's proposed adjustment. Nevertheless, even if one were to accept Witness Neme's adjustment just for the sake of this comparison, then Witness Neme's load adjustment should also be applied to the 2016 1.5[%] EE sensitivity to place the comparison on the same basis. The inappropriateness of MEC's comparison of their Case 0 to DTE Electric's 2016 1.5% EE case can be demonstrated by comparing two of DTE Electric's scenarios that used different load assumptions. An example of a similar comparison that uses different load assumptions would be a comparison of the IRP 2016 Reference case against the Low Load sensitivity, which results in a $2 billion NPV difference between plans[.]

6 Tr 1785. In addition to the load forecast used in Mr. Evans' Case 0, Mr. Chreston also disagreed with the assumptions for EE, DR, renewable energy, and plant cost that were incorporated in that model run. However, he reiterated that even without correcting these assumptions, the company's proposed project was the most economical. 6 Tr 1786-1787, Exhibit A-77. Mr. Chreston highlighted Case 0_B_DTE in Exhibit A-77, explaining that this sensitivity was based on Mr. Evans' Case 0 with corrected heat rates as pointed out in Mr. Evans' supplemental testimony, as well as the O&M adjustments to the proposed project recommended by Mr. Allison. "This optimization results in a plan that includes the Proposed Project in 2023 and is $545 million cheaper than Witness Evan's Case 0." 6 Tr 1788.

<u>Discussion</u>

As is obvious from the discussion of the record above, integrated resource planning requires myriad assumptions. The Commission believes there is great value to have MEC/NRDC/SC's modeling results to consider as part of this case. The large swings between Mr. Evans' Case 0, which adjusted DTE Electric's Reference Case, and DTE Electric's adjustments in response to those adjustments demonstrate that changing even one assumption can alter results in a significant fashion, and it underscores the need for additional transparency in modeling. Nonetheless, the Commission finds that the validity of MEC's claimed $1.8 billion savings was rebutted by DTE

Electric, and that no party refuted DTE's findings at later points in this case (during cross examination, in briefs, or in reply briefs) and as a result, the Commission is unable to rely on this claimed savings estimate when making decisions in this case.

The Commission agrees with the Staff, and several intervenors, that DTE Electric should have provided more detail in its modeling and screening concerning how the company developed optimal EE, renewables, and DR levels in its IRP. Modeling by both Mr. Evans and Mr. Chreston shows that achieving 2% annual energy savings could defer the proposed plant by one year, to 2023. 6 Tr 1787-1788, Exhibit A-8. An investment in energy efficiency at this level, if feasible, would also provide flexibility and mitigate risks in the event coal plant retirements occur earlier than planned, or the gas plant construction is delayed either intentionally due to potential cost savings from a later in-service date or unintentionally due to permitting or construction challenges. Moreover, combining incremental EE with other options that can be scaled up over time, such as DR and renewable energy, would provide a diverse resource portfolio that could displace the second gas plant in the late 2020s.

Nevertheless, the 2% savings level does not displace the proposed gas plant, it only defers it by one year. And the Commission has some reservations about the ability to scale up and sustain 2% annual energy savings. First, the company has only recently updated its plan to achieve overall EE savings of 1.5%. This represents a significant increase above the company's prior 1.15% EE savings per year, and, although the plan contains programs designed to achieve 1.5% EE savings, there is no way to know at this early stage of the plan whether the planned savings will in fact materialize. The Commission has made adjustments to refine and increase the rigor of EM&V approaches and tools to verify savings for compliance and to determine financial incentives. This could make it more challenging for utilities to achieve and sustain a 2% annual savings level over an extended period. Further, the Commission is persuaded by the company's testimony that very few utilities have actually met, let alone exceeded, an EE savings objective of 2%. Finally, there is beginning to be some indications that despite how popular or successful residential EE programs are, other factors are at work that may be offsetting those energy efficiency savings, whether through the purchase of more electrical products or more use of energy efficient products, simply because they are energy efficient. Even though DTE Electric and other utilities have been consistently achieving 1% savings or higher under existing EE programs since the 2008 law, corresponding reductions in actual sales are not occurring. Accordingly, the Commission has in recent rate cases called for staff to examine further load forecasting methodologies and the relationship to EE. *See,* e.g., March 31, 2018 order in Case No. U-18322, p. 50 and April 18, 2018 order in Case No. 18255, p. 36.

Turning to DR, the Commission finds DTE Electric's plan to add only 125 MW of incremental DR to its current portfolio is overly conservative given the results of two potential studies. But again, the Commission is reluctant to assume that, given the company's limited experience with new DR program marketing and deployment outside of small-scale pilots and the uncertainty surrounding customer receptivity to TOU rates, DTE Electric could effectively ramp up its DR program to the levels necessary to offset a significant amount of capacity the company will require in 2022 and 2023. Residential customer adoption of TOU rates represents a significant amount of the near-term DR identified in the statewide potential study. The Commission finds it is necessary to further test the marketing of TOU rates given the limited participation to date, as well as customer interest in and response to TOU rates, including persistence of demand savings under this rate design/DR option.

In order to reduce barriers to market-based demand response and in anticipation of evolving FERC policy, the Commission is considering removing the current ban on third parties enrolling regulated utilities' bundled customers in non-utility demand response programs and bidding that resource into the wholesale market. *See,* March 29, 2016 order in Case No. U-16020. The Commission is monitoring FERC proceedings as FERC revisits, and perhaps limits, its policy with respect to states' ability to ban DR aggregation. Accordingly, the Commission directs the DR Workgroup to begin to evaluate coordination and communication issues among aggregators, customers, the Commission, utilities, and MISO, that may need to be addressed if third party DR aggregation is permitted in the future. The DR Workgroup may want to consider models in other states, such as Indiana.

The Commission does not anticipate significant growth in DR through aggregation due to MISO's wholesale market design with depressed capacity prices. Thus, such a policy change on aggregation is highly unlikely to alter the need for the proposed gas plant but the Commission is interested in removing regulatory barriers in the event market conditions change.

In addition, to facilitate the ability of customers to utilize technologies and work with third parties to manage their energy use and costs, the Staff should engage with DTE Electric in the ongoing data access tariff update proceeding, in Case No. U-18485 to ensure that utilities provide timely access to consumption data in a usable format so customers can work with third parties to manage their energy use and costs in conformance with Commission's recently updated billing rules.

Ultimately, the Commission finds that a narrow window exists prior to the planned coal plant retirements that may not allow sufficient time for ramping up significant quantities of renewable energy, EE, DR, storage, or other options in order to completely displace the need for the proposed gas plant. Even if such options were feasible as a comprehensive portfolio to replace the gas plant under this timeframe, the cost is higher. 6 Tr 1788. And as discussed above, without replacement generation, there are potential operational reliability issues that could arise given the significant amount of generation retiring in a concentrated area. Generators provide voltage support and other ancillary services that support the transmission system. There is no dispute among the parties that, due to the coal plant retirements, there is additional need for capacity in the early 2020s even with the construction and operation of the proposed gas plant. DTE Electric has identified EE, renewable energy and market purchases to fill this near-term, relatively modest need of approximately 300 MW. In addition, the record shows that these resources, particularly increased DR, EE and renewable energy, could potentially displace—not just defer—the second gas plant identified in the company's IRP for 2029.

DTE Electric has not committed to a specific strategy to fill this near-term capacity need or the more significant, longer-term need over this 10-year horizon. Given potential changes in customer demand, technology costs, and other factors, the Commission would expect these resource plans and commitments to continue to evolve over time and adapt to changing conditions. Modeling results presented in this case showed potential customer savings by augmenting the proposed gas plant with incremental EE. When considering long-term needs and risks, the gas plant combined with incremental EE appears to be the most reasonable and prudent option assuming that energy efficiency in the range of 1.5-2% is feasible. Unlike the new IRP process, the CON is not set up to review and approve a portfolio approach such as the proposed plant combined with energy efficiency and other resources. Some parties suggested the Commission deny the CON and have DTE Electric re-file under the new IRP guidelines. In addition to the legal considerations with such approach, the Commission is concerned that the delay could create regulatory uncertainty that is reflected in future bids, thereby raising costs, and there is a need to proceed with construction in 2019 to ensure reliability as coal plants are retired.

Nevertheless, as these options and decisions about resource plans to complement the gas plant continue to be explored, the Commission wants to avoid a situation in which low-risk, cost-effective options such as EE and DR, which need time to scale up and that depend on voluntary customer participation, are limited or foreclosed from meeting a longer term need due to a lack of timely commitment by the utility.

Accordingly, the Commission finds that sufficient time exists for the company to develop and analyze a cleaner alternative portfolio in place of the second natural gas-fired plant identified by the IRP to fill a capacity need in 2029. The Commission looks forward to addressing these issues in detail in the company's 2019 IRP filing, and benefitting from additional analysis and dialogue with stakeholders on how these options can ensure a balanced, reliable, and adaptable portfolio in the near and long term. To ensure that the Commission can properly evaluate all options, the Commission directs DTE to file in its 2019 IRP application under Section 6t, an additional scenario that shows a portfolio consisting of EE, renewable energy, DR, storage, and other non-fossil fuel options, ramping up over the years preceding 2029, resulting in a cleaner alternative 2029 portfolio, that could augment the proposed 2022 NGCC and accommodate the retirement of Belle River, without the need for an additional gas plant. This scenario would be in addition to the optimal portfolios presented by the Company based on the scenarios adopted by the Commission in the November 21 and December 20 orders. Should the Company find that the timing of the 2029 capacity need has shifted to some later point in the future, in the company's next IRP, DTE Electric is still directed to develop and analyze a similar cleaner alternative portfolio to be presented alongside any other optimal portfolios that may be developed in the Company's next IRP.

DTE Electric is also expected to outline the associated timing, procurement strategies, and programmatic approaches to scale up these resources to meet this need in a cost-effective, reliable manner. DTE Electric, the Commission, and stakeholders would be well served by the company's coordination with the Staff and other interested parties in the development of such scenario before the IRP is filed. And to be clear, in determining the IRP in the instant proceeding complies with law, the Commission is in no way endorsing or determining the reasonableness of a second gas plant or even any planning activities by DTE Electric to pursue such a plant. In fact, there is compelling evidence to suggest that a second plant could be avoided.

While these resource planning decisions will be addressed in the 2019 IRP, the Commission also expects to closely examine in other Commission proceedings (i.e., rate cases, PSCR cases, and renewable energy and energy waste reduction plan cases, as applicable) DTE's purchases and other actions to arrange energy and capacity going forward, particularly the prudency of costs that could be avoided or mitigated if more cost-effective resources are available.

c. Alternative Purchase of a Facility or Power Purchase Agreement

The CON and IRP guidelines do not have requirements for bidding of alternatives such as a PPA or plant purchase. Ms. Dimitry testified that in March 2017, DTE Electric issued an RFP for both natural gas fueled generating assets and PPAs that could address short-term capacity deficits as an alternative to the gas plant proposed to be owned and operated by DTE Electric. 6 Tr 1614. Ms. Dimitry stated that conforming bids were required to meet the following specifications: (1) combined or simple-cycle NGCC technology; (2) must qualify for MISO capacity credit by the 2022 planning year; (3) unforced capacity (UCAP) between 225 and 1,100 MW; (4) must be