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March 12, 2018

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, Michigan 48917

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

Dear Ms. Kale:

Attached for electronic filing in the above captioned matter is DTE Electric Company's Reply Brief. Also attached is the Proof of Service.

Very truly yours,

David S. Maquera

Digitally signed by David S. Maquera
DN: cn=David S. Maquera, o=General Counsel - Regulatory, ou=General Counsel - Regulatory, email=david.maquera@dteenergy.com, c=US
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David S. Maquera

DSM/lah
Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

DTE ELECTRIC COMPANY'S REPLY BRIEF

Dated: March 12, 2018

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I. INTRODUCTION.

On March 2, 2018, DTE Electric Company ("DTE Electric" or the "Company") filed its Initial Brief in this case. Initial briefs were also filed by Staff, Attorney General Bill Schuette ("AG"); the Association of Businesses Advocating Tariff Equity ("ABATE"); the Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (collectively "MEC/NRDC/SC"); the Ecology Center, Solar Energy Industries Association, Union of Concerned Scientists, Environmental Law & Policy Center, and Vote Solar (the self-named "Clean Energy Groups" or "CEG," but for clarity here, the "ELPC"); and Michigan Energy Innovation Business Council ("MEIBC"). Neither International Transmission Company ("ITC"), Midland Cogeneration Venture ("MCV"), nor City of Ann Arbor filed initial briefs.

This reply will generally follow the order of DTE Electric's Initial Brief, which in turn generally followed the order and requirements of the three certificates of need ("CONs") that the Company seeks. To avoid repetition and disjointed discussions, DTE Electric will collectively address the other parties' related arguments, noting matters that appear resolved, and including some discussion for context, but avoid belaboring or repeating matters. DTE Electric relies on the content of its Initial Brief (which largely anticipated and addressed the other parties' suggestions), along with its testimony and exhibits, and incorporates the same as if restated here. DTE Electric will attempt to be thorough, but notes that it is not (nor is it required to be) clairvoyant, and objects to the extent any party's Initial Brief does not articulate or explain a position to which DTE Electric can respond. Also, some matters extend beyond this case, or are more properly addressed in other cases. DTE Electric has and will respond as appropriate in other contexts.[1] Lack of a discussion

[1] It has been suggested that DTE Electric was unwilling to cooperate with others in attempting to reach agreement on issues to be briefed. To the contrary, the Company was open to agreement (as the numerous email exchanges will confirm), but maintained that this case must focus on the three CONs that the Company is requesting. Other parties raised a number of issues that are not pertinent here.

by DTE Electric to separately address every issue or position suggested or inferred should not be construed as agreement. DTE Electric, of course, maintains all of its appellate rights.

II. BACKGROUND AND SUMMARY OF MAJOR ISSUES.

Despite an evidentiary record exceeding thousands of pages of evidence and hundreds of pages of closing arguments via briefs, this case remains relatively simple. DTE Electric's Initial Brief, pp 7-9, explained that the Company plans to retire eight (8) coal-fired generating units (the River Rouge, St. Clair, and Trenton Channel power plants) by 2023 due to age, environmental requirements, and the Company's commitment toward building a cleaner, sustainable generation fleet.[2] The Company proposes to replace that lost coal-fired capacity (approximately 1,822 MW) primarily with a 1,100 MW combined cycle gas plant (the "Proposed Project"). The Company's Integrated Resource Plan ("IRP") and other evidence demonstrate that building the Proposed Project is the most reasonable and prudent course of action to ensure reliable and cost-effective energy and capacity for customers in the future, along with demand response, necessary renewables and energy efficiency as well as minor market purchases or other resources as appropriate. Accordingly, DTE Electric seeks the following three CONs under MCL 460.6s(3):

1. A CON that the power to be supplied by the Proposed Project is needed.

2. A CON 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

3. A CON 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.

[2] During this proceeding, St. Clair Unit 4 was retired, thereby leaving only seven coal plants remaining to be retired between 2020 and 2023.

The other parties representing public interests agree that the CONs should be issued. Staff recommends that the Commission approve DTE Electric's three requested CONs (Staff Initial Brief, pp 1, 7, 50). The AG states that the "Company sufficiently demonstrated the need for the power generated by the Proposed Project through the coal retirement analysis in its IRP" . . . [and] the Commission can reasonably find that DTE Electric showed that the proposed Project was the most reasonable and prudent means of supplying the needed power" (AG Initial Brief, p 10). The Staff and AG raise some issues (for example, the nature of DTE Electric's next IRP, which is scheduled to be filed in March of 2019, and the level of contingency cost recovery in this case), but the bottom line – that the requested CONs should be issued – does not change.

In contrast, the trade association and environmental intervenors support their individual industry and policy objectives with hyperbole, stray issues, and other distractions apparently designed to try to convince the Commission that there are so many possible things that could be considered, there is no way to pick just one, so the CONs must be denied. That approach is contrary to the statutory scheme envisioning timely and actual progress as indicated in DTE Electric's Initial Brief and further discussed below. While one could always speculate about possibilities, nobody proposes any actual alternative to the Proposed Project.

III. JURISDICTION AND STANDARD OF REVIEW.

DTE Electric's Initial Brief, pp 9-14, discussed the Commission's jurisdiction over this case, as well as the applicable standard of review. Despite the well-established and controlling requirements, some parties suggest that the Commission should rule otherwise.

For example, MEC/NRDC/SC assert that "DTE's CON requests can only be granted if, among other things, the Commission determines that DTE has met all of the requirements in subsections (a) through (e) of MCL 460.6s(4)" (MEC/NRDC/SC Initial Brief, p 6). However, the statute instead provides that: "The *commission shall grant the request if* it determines all of the following…" Under well-settled rules of statutory construction, MCL 460.6s(4)'s plain language (quoted in DTE Electric's Initial Brief, p 10) must be applied as written.[3] In this instance, the statute uses the term "shall," which denotes a mandatory duty imposed by the Legislature and excludes the idea of administrative discretion.[4] MCL 460.6s(4) goes on to list requirements, the first of which is:

> "(a) That the electric utility has demonstrated a need for the power that would be supplied by the existing or proposed electric generation facility or pursuant to the proposed power purchase agreement through its approved integrated resource plan under section 6t or subsection (11)."

MEC/NRDC/SC assert: "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 Initial Brief, pp 7-8).

Staff disagrees with MEC/NRDC/SC. In fact, Staff concluded that "Staff believes the Company met the minimum standard for an IRP analysis that was available at the time of filing" (Staff Initial Brief, p. 23).

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[3] *Elozovic v Ford Motor Co*, 472 Mich 408, 421-22, 425; 697 NW2d 851 (2005) ("The text must prevail. . . . The Legislature is held to what it said. It is not for us to rework the statute. Our duty is to interpret the statute as written"); *Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

[4] *Macomb Co Rd Comm'n v Fisher*, 170 Mich App 697, 700; 428 NW2d 744 (1988); *Southfield Twp v Drainage Bd*, 357 Mich 59, 76-77; 97 NW2d 281 (1959) ("the word 'shall' is mandatory and imperative and, when used in a command to a public official, it excludes the idea of discretion").

More importantly, 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. See, for recent example, *Taylor v Taylor*, ___ Mich App ___ ; ___ NW2d ___ (February 22, 2018; 2018 WL 1020621 at *1 ("The word 'or' is disjunctive and 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").

Moreover, DTE Electric does not have an "approved integrated resource plan under section 6t," and will not have one for some time. The filing deadline for DTE Electric's section 6t IRP application is more than a year in the future, on March 29, 2019 (December 20, 2017 Order in Case Nos. U-15896 and U-18461, p 4). Therefore, proceeding under "subsection (11)" is not only an option, it is *the only available* option for this case.

DTE Electric also previously discussed the preponderance of evidence standard that applies in this proceeding.[5] The "preponderance of the evidence" standard is generally defined as follows:

> "***The greater weight of the evidence***, not necessarily established by the greater number of witnesses testifying to a fact but by evidence that has the most

[5] October 25, 2017 Order in Case No. U-18224, p 15. See also *Aquilina v General Motors Corp*, 403 Mich 206, 210-211; 267 NW2d 923 (1978) ("The proof required in an administrative proceeding…is the same as that required in a civil judicial proceeding: a preponderance of the evidence."). The preponderance of evidence standard is the lightest of all evidentiary standards when compared to the heightened "clear and convincing" standard[5] (*In re Moss*, 301 Mich App 76, 89-90; 836 NW2d 182 (2013)), or the "beyond a reasonable doubt" standard that is only applicable to criminal proceedings *Thangavelu v Dep't of Licensing & Regulation*, 149 Mich App 546, 554-555; 386 NW2d 584 (1986)).).

> convincing force; ***superior evidentiary weight that, though not sufficient to free the mind wholly from all reasonable doubt, is still sufficient to incline a fair and impartial mind to one side of the issue rather than the other***." *Black's Law Dictionary* 1301 (9th ed 2009). (Emphasis added).

Regardless, the trade association and environmental intervenors suggest, without basis, a higher standard – essentially that something more could always be considered, so nothing can ever be decided (See, for example, ELPC Initial Brief, pp 7-8, claiming without support that there is "an insufficient record for the Commission to determine, with the necessary degree of confidence, that building an 1,100 MW combined cycle gas plant is the *most reasonable and prudent* investment for DTE's customers." Emphasis in original). To the contrary, the statute calls for prompt decision-making in 270 days,[6] which precludes the suggestions to remain locked in never-ending analyses of further possibilities or to abdicate decision-making because one can never "confidently" predict what will be best for an inherently uncertain future. An extensive record was made in this case and a decision must be based on that record.[7] To the extent that any intervenor thought that anything else should be in the record, they plainly had the opportunity and

[6] MCL 460.6s(4) relevantly states:

> "***Within 270 days after the filing of an application under this section***, or, for an application for an electric utility facility submitted as required under section 6t(13), concurrently with a final order issued under section 6t, ***the commission shall issue an order granting or denying the requested certificate of necessity***" (Emphasis added)

See also, July 12 Order, pp 3, 6 (recognizing MCL 460.6s(4)'s language, and directing the ALJ to "approve a schedule that will permit the Commission to issue a final order approving or denying DTE Electric's application within 270 days of its filing").

[7] Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, Art 6, § 28. The Administrative Procedures Act ("APA") precludes the Commission from making decisions based on non-record materials. MCL 24.276.

means to further add to the already-voluminous record.[8] Adoption of the trade association and environmental intervenors' suggestion would result in Commission "paralysis by analysis."

The need for power created by the Company's planned coal plant retirements is essentially undisputed, so the controversy in this case focuses on whether the Proposed Project represents under MCL 460.6s(4)(d) "the most reasonable and prudent means of meeting the power need relative to other resource options…" due to planned coal plant retirements. As our Supreme Court recently explained in *MDEQ v Worth Twp,* 491 Mich 227, 237-38; 814 NW2d 646 (2012):

> "… this Court must 'ascertain and give effect to the intent of the Legislature.' The words used in the statute are the most reliable indicator of the Legislature's intent and should be interpreted on the basis of their ordinary meaning and the context within which they are used in the statute. In interpreting a statute, this Court avoids a construction that would render any part of the statute surplusage or nugatory. 'As far as possible, effect should be given to every phrase, clause, and word in the statute.' Moreover, the statutory language must be read and understood in its grammatical context. When considering the correct interpretation, the statute must be read as a whole, unless something different was clearly intended. Individual words and phrases, while important, should be read in the context of the entire legislative scheme" [footnotes omitted].

With this guidance from the Michigan Supreme Court, the above-quoted language of MCL 460.6s(4)(d)) breaks down into three parts:

1. "the most reasonable and prudent." The reasonable and prudent standard is well known to the Commission and involves various considerations, particularly reliability for customers as DTE Electric indicated in its Initial Brief. If the Legislature intended some different standard (such as the least expensive, or one that favored a certain level of renewable resources, etc.), then the Legislature "surely could have said so." *Lash v Traverse City,* 479 Mich 180, 189;

[8] The procedural history for this case shows that the intervenors persuaded the ALJ to grant them an additional 30 days for preparing their direct testimony even though it would have prevented the Commission from complying with the 270-day statutory deadline for a final order. Ultimately, the Commission decided to forego the benefit of a proposal for decision and "read the record" since it was the only way to issue a timely final order. See *In re DTE Electric Co,* MPSC Case No. U-18419, Order dated Jan. 23, 2018, Dkt. No. 292.

735 NW2d 628 (2007); *see also*, *People v McIntire*, 461 Mich 147, 160; 599 NW2d 102 (1999); *Farrington v Total Petroleum, Inc*, 442 Mich 201, 210; 501 NW2d 76 (1993) ("Courts cannot assume that the Legislature inadvertently omitted from one statute the language that it placed in another statute, and then, on the basis of that assumption, apply what is not there").

2. "means of meeting that power need." This plainly refers to a way of actually meeting the need to replace power presently generated by the coal plants that DTE Electric has proposed to retire. It is not a mere "possibility" nor is it something to address just "part of" the power need. Again, if the Legislature had meant something different, then it would have said so. This matter is further discussed below in detail.

3. "relative to other resource options." Here, an "option" is "an alternative course of action." *Merriam Webster's Collegiate Dictionary* (11th ed).[9] Again, it is not a mere possibility.

DTE Electric supported its Proposed Plant. Nobody offered, let alone supported, a viable alternative to the Company's Proposed Project. Suggestions that something else might possibly be considered is no basis to reject the best and only alternative on the record. If other parties had a better alternative, then the burden was on them to present it. Indeed, MCL 460.6s(13) specifically contemplates "the ability of any other person to submit to the commission an alternative proposal."

The Commission has also recognized in analogous circumstances that "once a utility has satisfied its initial burden of proof, another party 'may challenge that evidence and present evidence of unreasonableness.' However, at that point, the other party has the burden to demonstrate its position is correct.'" October 25, 2017 Order in Case No. U-18224, pp 14-15, quoting January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 38. Staff

[9] Our Supreme Court used this same dictionary in *Covenant Medical Center v State Farm Mut Ins Co*, 500 Mich 191; 895 NW2d 490 (2017) and *City of Coldwater v Consumers Energy Co*, 500 Mich 158; 895 NW2d 154 (2017).

agrees (Staff Initial Brief, p 5). This evidentiary standard also effectively bars last-minute criticisms of the Company's evidentiary presentation, as the Commission further explained:

> "The Commission finds that a delicate balance must be maintained concerning the burden of proof. The company has the burden of going forward and demonstrating that it has proposed just and reasonable rates. In this instance, Detroit Edison made that showing. The Staff in response may challenge that evidence and present evidence of unreasonableness. At that point, however, the Staff has the burden to demonstrate its position is correct. The company may then rebut the Staff's criticisms of its case. The problem here is that the specific criticism that the company had not adequately explained itself came too late in the process for a fair determination on that issue, particularly given the evidence the company presented in support of its position (January 11, 2010 Opinion and Order in case Nos. U-15768 and U-15751, pp 37-38).

This same response essentially applies to MEC/NRDC/SC's newly-announced claim that the Commission allegedly cannot find that DTE Electric's Proposed Project complies with the Michigan Environmental Protection Act ("MEPA"), MCL 324.1701 *et seq*. (MEC/NRDC/SC Initial Brief, pp 10-13, 94-95). MEC/NRDC/SC assert: "When a *prima facie* case of harm or potential harm is established, the entity emitting the pollution must demonstrate that there is 'no feasible and prudent alternative' that would achieve the objective of the proposed action" (MEC/NRDC/SC Initial Brief, p 11, citing MCL 324.1703).

MEC/NRDC/SC's newly-announced MEPA claim fails by MEC/NRDC/SC's own cited authority since MEC/NRDC/SC have not "established" a "*prima facie* case of harm or potential harm." Indeed, they have not even attempted to make any showing and cite no evidence upon which any such potential harm could be found as required by the Commission's rules.[10] Instead, as reflected in DTE Electric's Initial Brief, pp 79-80, the Proposed Project will comply with all applicable environmental regulations (5T 1442-43. See also 5T 1473-74). The Proposed Project

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[10] Commission Rule R 792.10434 requires in pertinent part that: "Briefs containing factual allegations claimed to be established by the evidence shall include a reference to the specific portions of the record where the evidence may be found." See R 792.10434(3).

will also use state of the art emission control technology, thereby resulting in the significant reduction in all emissions from the Proposed Project as compared to the retiring coal plants (5T 1444-47; Exhibit A-36 Revised estimates emissions over the life of the Proposed Project). Staff agrees that “it is reasonable to expect that the Proposed Project will comply with all applicable state and federal environmental standards, laws, and rules” (5T 183. See also, Staff Initial Brief, pp 14-16). Staff further recognizes that “the proposed project is in the interest of ratepayers, due to its ability to provide affordable capacity and reduce emissions versus coal” (Staff Initial Brief, p 1).

MEC/NRDC/SC further assert the generic conclusory statement that: “Electric generating units are responsible for the majority of air pollution being emitted from smokestacks in the state of Michigan” (MEC/NRDC/SC Initial Brief, p 94). However, that non-record statement is not even evidence. The Administrative Procedures Act (“APA”) precludes the Commission from making decisions based on non-record materials. MCL 24.276 provides that: “Evidence in a contested case . . . shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case except as permitted under [MCL 24.277 concerning official notice of judicially cognizable facts and facts within the agency’s specialized expertise].” Noncompliance with the APA is reversible error.[11]

In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained that:

> “The party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation.”

Thus, unproven allegations cannot stand in the place of evidence. Things not proven must be taken as not existing, since a decision cannot be based upon conjecture. *Star Steel v USF&G*, 186 Mich

[11] *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

App 475, 481; 465 NW2d 17 (1990); *see also, Skinner v Square D Co,* 445 Mich 153; 516 NW2d 475 (1994). It is similarly well established that an agency decision may not be based on speculation.[12] Based on the above legal authorities, MEC/NRDC/SC's non-record conclusory statement is clearly not a basis for a Commission decision in this case as a matter of law.

MEC/NRDC/SC appear to suggest that the Commission should somehow take administrative notice, but do not indicate what the Commission supposedly should notice. The suggestion is also plainly improper under applicable rules.[13] The Commission recently explained that "because of the unforgiving time limits under MCL 460.6a [which at that time had a 12 month deadline, which was far longer than the 270 day deadline applicable in this case], official notice requests, especially those that may generate controversy regarding the materiality or weight of the evidence proffered, can rarely, if ever, be entertained after the close of the record" (December 11, 2015 Order in Case No. U-17767, p 136, agreeing with ALJ's denial of official notice request).

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[12] *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by evidence that a reasonable person would consider adequate).

[13] Rule 428 of the Commission's Rules of Practice and Procedure provides:

> "Except as otherwise provided by law, the commission and the presiding officer ***may take official notice of judicially cognizable facts and may take notice of general, technical, or scientific facts within the commission's specialized knowledge***. The commission or the presiding officer shall notify the parties at the earliest practicable time of any noticed fact that pertains to a materially disputed issue that is being adjudicated and, on timely request, the parties shall be given an opportunity before the final decision to dispute the fact or its materiality. The commission may use its expertise, technical competence, and specialized knowledge in the evaluation of evidence presented to it" (R 792.10428. Emphasis added).

MRE 201(b) similarly provides:

> "***A judicially noticed fact must be one not subject to reasonable dispute*** in that it is either (1) generally known within the territorial jurisdiction of the trial court or (2) capable of accurate and ready determination by resort to sources whose accuracy cannot reasonably be questioned" (Emphasis added).

See also *Freed v Salas*, 286 Mich App 300, 341; 780 NW2d 844 (2009), where the Court of Appeals affirmed the trial court's refusal to take judicial notice of a speed limit, explaining in part: "Given that the signage and the traffic control order did not agree as to the speed limit for the area, the fact could not reasonably be said to have been undisputed or capable of accurate and ready determination."

Moreover, since MEC/NRDC/SC did not make any "*prima facie* case of harm or potential harm," DTE Electric has nothing to which it can respond, and so is left with just broadly disagreeing and pointing out that the Proposed Project will comply with all environmental requirements and result in significantly less pollution, as indicated above and in DTE Electric's Initial Brief. There is similarly "'no feasible and prudent alternative' that would achieve the objective of the proposed action" under MEC/NRDC/SC's proposed standard (assuming for argument's sake that it could apply, which it does not), but again MEC/NRDC/SC do not attempt to support their newly-asserted argument, so DTE Electric simply incorporates its other discussions by reference, including the discussion above about the lack of *any* specific viable "alternative," let alone one that is "feasible." See also, Staff Initial Brief, p 14, which states: "Staff can only assume that since no other alternatives were presented to the Commission, no other feasible alternatives are available at this time." DTE Electric also objects on due process grounds to MEC/NRDC/SC's newly-announced, unsupported, and unexplained argument, which effectively evades any specific response.[14]

[14] DTE Electric also has due process rights under the Fourteenth Amendment to the United States Constitution. Michigan's Constitution similarly provides DTE Electric with the right to fair and just treatment in MPSC proceedings: "No person shall be compelled in any criminal case to be a witness against himself, nor be deprived of life, liberty or property, without due process of law. The right of all individuals, firms, corporations and voluntary associations to fair and just treatment in the course of legislative and executive investigations and hearings shall not be infringed." Const 1963, art 1, § 17.

DTE Electric further notes that MEC/NRDC/SC did not, and do not, seriously present any MEPA issue for consideration in this proceeding. Instead, their newly-announced claim appears to be just posturing for a potential appeal based on *Buggs v Public Service Comm'n,* unpublished opinion per curium of the Court of Appeals, issued January 15, 2015 (Docket Nos. 315058 and 315064) (2015 WL 159795, cited at MEC/NRDC/SC Initial Brief, p 12) (remanding MPSC orders approving the construction and operation of natural gas pipelines for further proceedings). However, MEC/NRDC/SC neglect to mention that on remand the Commission again approved the construction and operation of natural gas pipelines, and the Court of Appeals affirmed. *In re Application of Encana Oil & Gas Re Garfield 36 Pipeline*, unpublished opinion per curium of the Court of Appeals, issued May 16, 2016 (Docket Nos. 329781 and 329909; 2017 WL 2130276).

The Commission is undoubtedly aware of these cases, so DTE Electric will not belabor the details. The bottom line is that in this CON case, there is no environmental issue and no defect with the record evidence on environmental matters, as discussed above. However, the Commission should take care in articulating its order in light of the disappointing level to which some parties seem willing to go to "throw sand in the gears" of these proceedings and Michigan's energy future in an effort to advance their own objectives.[15]

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[15] See also, *Sierra Club v Dep't of Environmental Quality*, unpublished opinion per curiam of the Court of Appeals, issued November 21, 2013 (Docket Nos. 308072 and 314152), where the Court of Appeals rejected the Sierra Club's opposition to modifying DTE Electric's power plants to reduce emissions, recognizing that such an extreme position would lead to an absurd result. The Court also rejected MEC's attempt to shut down DTE Electric's coal-fired power plants, which could have detrimentally impacted customers in advance of the Company's present proposal to replace such lost capacity with the Proposed Project. *In re Application of Detroit Edison Company to Increase Rates*, unpublished opinion per curiam of the Court of Appeals, issued July 30, 2013 (Docket Nos. 308130, 308154, and 308156).

Thus, for reasons discussed above, MEC/NRDC/SC waived[16] and abandoned[17] their newly-asserted MEPA issue. To the extent that the Commission considers the MEPA issue in response to MEC/NRDC/SC's latest posturing, the issue fails as unsupported by any evidence, overwhelmingly refuted by the record, and otherwise contrary to law.

IV. DTE ELECTRIC SATISFIED THE APPLICABLE FILING REQUIREMENTS FOR ITS REQUESTED CONS.

DTE Electric's Initial Brief, pp 14-15, noted the *applicable* Integrated Resource Plan ("IRP") filing requirements under MCL 460.6s(11) and the Commission's May 11, 2017 Order in Case No. U-15896. Staff's witness observed that the Commission recently issued further guidance through its November 11, 2017 Order in Case No. U-18418, but acknowledged that "this guidance was not available to DTE at the time of its filing," so it should only apply in future cases (5T 185). Staff's Initial Brief similarly notes the November 11, 2017 Order in Case No. U-18418, plus the December 20, 2017 Order in Case Nos. U-15896 and U-18461, but maintains the same conclusion that DTE Electric satisfied the applicable filing requirements. Staff states, for example: "Because this guidance was not fully developed at the time of DTE's filing, Staff submits that it does not apply to DTE's application" (Staff Initial Brief, p 2); and: "This detailed and important guidance was not available to the Company when it conducted its IRP analysis in 2016 and the updated analysis in 2017. Keeping in mind the guidance and standards at the time, the Company has met the minimum statutory standard in completing its analysis of the proposed project" (Staff Initial Brief, pp 23-24). Staff further concludes that: "DTE has satisfied the current CON requirements by demonstrating

[16] *Wiersma v Michigan Bell Telephone Co*, 156 Mich App 176, 185; 401 NW2d 265 (1987) ("The state, as well as an individual, may be estopped by its acts, conduct, silence and acquiescence").

[17] *See generally, Gross v General Motors Corp*, 448 Mich 147, 161-62, n 8; 528 NW2d 707 (1995) ("Failure to properly brief an issue on appeal constitutes abandonment of the question").

through its IRP that the power is needed and that its proposed facilities are the most reasonable and prudent means of meeting that need" (Staff Initial Brief, p 7).

MEC/NRDC/SC acknowledge that "DTE filed its application a few months before these standards were adopted," but then claims without support that these MCL 460.6t "standards and filing requirements are instructive in this proceeding because they show the level of analysis and documentation that an IRP must contain in order to provide the types of analyses needed to satisfy the requirements of MCL 460.6s(11)" (MEC/NRDC/SC Initial Brief, p 9). See also, ELPC Initial Brief, p 6, asserting without support that "DTE should be held to the standards established in the 2017 IRP Order." However, it is well-settled law in Michigan that a party's statement without authority is insufficient to bring an issue before a court.[18] Furthermore, it is not sufficient for a party to simply announce a position or assert an error and then leave it up to the court to discover and rationalize the basis for its claims, or unravel and elaborate for him his arguments, and then search for authority either to sustain or reject his position.[19] Notwithstanding MEC/NRDC/SC's and ELPC's unsupported assertions, DTE Electric incorporates the discussion above regarding MEC/NRDC/SC's unlawful suggestion to disregard 460.6s(11), as if only MCL 460.6t exists.

DTE Electric also agrees with Staff that it is not required to be clairvoyant or otherwise foresee and comply with future requirements. The Company performed a robust analysis with reasonable information available at the time. Attempts to impose new obligations that impair DTE Electric's expectations and rights would be unlawful and unreasonable. See, for example, October 25, 2017 Order in Case No. U-18224, p 13. The November 11, 2017 Order in Case No. U-18418 and December 20, 2017 Order in Case Nos. U-15896 and U-18461 were issued well after the Company filed its

[18] *Wilson v Taylor*, 457 Mich 232, 243; 577 NW2d 100 (1998).

[19] *Id*, citing, *Mitcham v Detroit*, 355 Mich 182, 203; 94 NW2d 388 (1959).

application for CONs under MCL 460.6s. Those orders also concern Section 6t rather than Section 6s. DTE Electric has been assigned the date of March 29, 2019 to file an integrated resource plan pursuant to MCL 460.6t. Since the Company currently does not have an integrated resource plan approved pursuant to MCL 460.6t, it is only appropriate to review the Company's integrated resource plan in accordance with MCL 460.6s(11). (6T 1635-38).

Staff also includes some commentary regarding DTE Electric's March 2019 IRP filing. Staff states, for example: "Staff recommends that the DTE's CON requests should be approved, along with a Commission directive for a more robust IRP filing in March 2019" (Staff Initial Brief, p 1). It is unclear what exactly Staff desires, which creates difficulty for DTE Electric to respond specifically. The Commission has already issued further guidance on future MCL 460.6t IRP filings, as indicated above. The Commission may issue additional guidance in the next year leading up to DTE Electric's presently-scheduled March 2019 filing. At the time of that filing, DTE Electric will endeavor to proceed appropriately in accordance with applicable law and whatever guidance is available to the Company at the time.

It also bears emphasis, as indicated above, that this case involves an IRP under MCL 460.6s(11). The case's scope and precedential value are limited in accordance with that statutory provision and it would be inappropriate to use this case to announce requirements for a different statutory provision (MCL 460.6t). The Commission already has separate proceedings for that purpose, as indicated above. See also, MCL 460.6t(3) ("The commission shall issue an order establishing filing requirements, including application forms and instructions, and filing deadlines for an integrated resource plan filed by an electric utility whose rates are regulated by the commission. The electric utility's plan may also include alternative modeling scenarios and assumptions in addition to those identified under subsection (1)").

Thus, DTE Electric satisfied the *applicable* filing requirements for its requested CONs. Rules can be changed, but changes cannot be applied retroactively.[20] Potential filing requirements for future IRPs or CON cases are beyond the scope of this discussion. Accordingly, the Company will proceed to discuss the merits of its proposal.

V. THE PREPONDERANCE OF THE EVIDENCE SHOWS THAT THE POWER TO BE SUPPLIED BY THE PROPOSED PROJECT IS NEEDED.

DTE Electric's Initial Brief, pp 16-28, explained that MCL 460.6s(4)(a)'s need requirement[21] is satisfied because DTE Electric needs power to replace the power that will be lost when DTE Electric retires old coal-fired generating plants due to their age and the costs of complying with pollution regulations. Staff agrees and recommends "that the Commission grant the certificate that the power supply is needed" (5T 182. See also Staff Initial Brief, pp 8-11, under the topic heading "DTE Electric presented an undisputed need for power through its IRP in compliance with MCL 460.6s(3)(a)."). The AG similarly states that the "Company sufficiently demonstrated the need for the power generated by the Proposed Project through the coal retirement analysis in its IRP" (AG Initial Brief, p 1).

MEIBC asserts that DTE Electric has not shown that the power to be supplied by the Proposed Project is needed (MEIBC Initial Brief, p 5, with argument continuing to p 18). While MEIBC's argument is characterized as if it questions the need for power, in substance the argument instead acknowledges the power need, but disputes how to fill that need. However, MEIBC's argument appears to be based on a unique reading of MCL 460.6s(4)(a), which states:

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[20] *Application of Michigan Consolidated Gas Co*, 304 Mich App 155, 173; 850 NW2d (2014) (vacating reconciliation orders because the Commission "acted unreasonably, or capriciously" in setting a prospective pricing change, then applying that change retroactively).

[21] The CON statute relevantly provides that the Commission shall grant the requested CON if, among other things, "the electric utility has demonstrated a need for the power that would be supplied by the existing or proposed electric generation facility." MCL 460.6s(4)(a).

"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 existing or proposed electric generation facility or pursuant to the proposed power purchase agreement through its approved integrated resource plan under section 6t or subsection (11)."

MEIBC essentially argues that the power from the Proposed Project is not needed because the power could be supplied by other means, which is not the question addressed under MCL 460.6s(4)(a). To the contrary, MCL 460.6s(4)(d) addresses the question regarding the most reasonable and prudent means of meeting the power need by stating that:

"The commission shall grant the request if it determines all of the following:

* * *

> "(d) The existing or proposed electric generation facility or proposed power purchase agreement 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."

The distinction between power need, and means to meet that power need, is further reflected by MCL 460.6s(3), which concerns the CONs that DTE Electric is requesting, and relevantly states:

"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 or the terms of the power purchase agreement represent the most reasonable and prudent means of meeting that power need.

Therefore, MEIBC's "need" argument will be discussed below, where it makes the most sense in substance, in the context of the Proposed Project representing the most reasonable and prudent means of meeting the power need.

That leaves only ABATE as the sole outlier party suggesting that DTE Electric should continue operating the aging coal plants because pollution control regulations might be delayed or otherwise change (ABATE Initial Brief, p. 8). ABATE's suggestion merits no serious consideration, but the Company responds below for completeness.

As indicated above, the need for the Proposed Project is largely driven by the Company's plan to retire eight (now seven) coal-fired generating units between 2020 and 2023. The necessity and appropriateness of moving away from coal-fired generation is driven both by increasingly strict environmental regulations and the Company's goal – consistent with customer feedback – to move toward a resource portfolio with lower carbon emissions. In 2014, the 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 (5T 1437, 1441; 6T 1731). The Company's environmental expert, Mr. Marietta further described environmental regulations, and how they impacted the Company's plan to retire the River Rouge, St. Clair, and Trenton Channel coal-fired power plants (5T 1435-41).

ABATE argues that the Company's Coal Retirement Analysis is flawed because the Clean Power Plan has been stayed, and it "appears that the current administration will repeal this proposed regulation in its entirety," . . . [and] the current administration has indicated its intent to review and potentially revise ELG requirements and compliance dates. The EPA has postponed certain compliance dates from 2018-2023 to 2020-2023" (ABATE Initial Brief, p 11).

ABATE's argument is overstated because the law has not changed. ABATE only speculates that it might change at some time in the future.[22] The Company's environmental expert Mr. Marietta further explained that it is not prudent for long-term planning purposes to use today's point-in-time regulations to presume to accurately predict the future. Mr. Marietta testified in part that:

> "As a country and industry we have seen abrupt changes to federal environmental regulations in recent years, and the Company has evaluated many regulations over time. Several regulations have undergone changes at various stages of rulemaking. Some regulations have been delayed or made less stringent. Others have become more restrictive or caused significant investment to be made more quickly than expected. The Company has evaluated the status of the ELG regulations and made the determination that the proposed project is the most prudent path forward based on the regulatory and other analyses" (5T 1451-52. See also 6T 1821-22).

Given the uncertainty about the scope and timing of possible revisions to environmental requirements (even assuming that there will ever be any such revisions), and also the age of the retiring plants and the costs to operate them beyond their announced retirements, the Company has concluded that the most reasonable and prudent plan is to close these older coal plants as announced and replace them with new, cleaner, more efficient, and more cost effective energy resources (6T 1604). DTE Electric also incorporates its discussion above about the impropriety of suggestions that the Commission should take administrative notice of disputed matters that are

[22] At this time, the U.S. Supreme Court has stayed the Clean Power Plan ("CPP"). The current administration has targeted the ELG for review and potential revision; however, 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 (5T 1451; 6T 1821-22).

not in the record (*e.g.*, ABATE Initial Brief, p 11, n 2, vaguely referencing what the "trade press" allegedly indicates about what the Trump administration might be doing).

The Company performed an economic analysis to determine the most prudent option between retiring unit(s) or investing capital required to comply with the revised environmental regulations. The results of the analysis showed that retirement of River Rouge Unit 3, St. Clair Units 1 - 3,[23] St. Clair Unit 6, St. Clair Unit 7, and Trenton Channel Unit 9 was favorable for customers compared to the capital investment and expenses required to safely operate and maintain these units and comply with the revised environmental regulations (6T 1604, 1728-33).

ABATE suggests that retirement may be inappropriate because DTE Electric will seek a $149 million increase in depreciation expense due to the coal plant retirements (ABATE Initial Brief, pp 9-10). However, Company witness Mr. Stanczak explained that the suggestion is inaccurate because the Company's request in its depreciation case, Case No. U-18150, is not exclusively due to updated coal plant retirement dates, but is also based on an expected increase in plant retirement costs. Case No. U-18150 is also pending, and its outcome is uncertain, so it is impossible to know what effect it may have on DTE Electric's next rate case (5T 1489-90).

ABATE is also inaccurate in suggesting that potentially-increased depreciation expense has significance in this case. To the contrary, the Company's expectation of full recovery of the retiring coal plants' capital cost and asset removal cost is not affected by the timing of the plant retirements. ABATE's suggestion is also misguided because the Company uses the Group Method of depreciation, under which 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 (5T 1490-91).

[23] St. Clair Unit 4 was retired during this proceeding.

ABATE is also inaccurate in suggesting that under the Tax Cuts and Jobs Act of 2017 ("TCJA"), the disposition of excess deferred taxes will impact this case (*e.g.*, ABATE Initial Brief, p 5). Excess deferred taxes, that in hindsight have been effectively over-accrued, are related to *existing* assets. They have nothing to do with assets that have or will be placed in service after January 1, 2018 (the TCJA's effective date). Thus, they have nothing to do with the Proposed Project. These deferred taxes were generally temporary and were always expected be paid as taxes. Now, however, rather than being fully paid to the government, the excess portion of the accrued deferred taxes will be returned to customers over time. This return of excess deferred taxes will happen regardless of whether the Company builds the Proposed Project (5T 1490-91).

ABATE's suggestion that the TCJA's effects must be fully accounted for here, or this case cannot be decided, also ignores that the Commission has already established a process for determining the TCJA's effects. On December 27, 2017 (just five days after President Trump signed the TCJA into law), the Commission opened a docket for Michigan utilities including DTE Electric "to solicit comments regarding the extent of the impacts of the new law, and how any resulting benefit should flow back to ratepayers" (December 27, 2017 Order in Case No. U-18494, p 2). The Commission also directed utilities to use regulatory accounting to consistently accrue ratepayer benefits beginning January 1, 2018 (the TCJA's effective date). *Id.* After receiving comments and replies from interested parties (including ABATE), the Commission issued a further order adopting the Staff's proposal "for addressing the TCJA that ensures that all potential impacts will be dealt with in a timely and deliberate manner, and all ratepayers will be made whole with respect to each category of benefit accruing from the federal tax reduction" (February 22, 2018 Order in Case No. U-18494, p 10). It is frivolous for ABATE to continue pursuing TCJA arguments that ignore the Commission's procedure for addressing the TCJA.

ABATE's suggestion that the Company's Coal Retirement Analysis is no longer relevant similarly fails to make any relevant point (*e.g.*, ABATE Initial Brief, pp 5-6). The record reflects that the TCJA has a minimal impact on the Coal Retirement Analysis, so no revision is warranted (6T 1822-23). ABATE witness Mr. Phillips' claims about DTE Electric's modeling of the Coal Retirement Analysis similarly lack merit and relevance (6T 1824-25).

ABATE inaccurately suggests that no retirement decision can be made because DTE Electric did not define a threshold level of materiality for TCJA effects on analyses (ABATE Initial Brief, p 7, selectively quoting DTE Electric witness Mr. Chreston at 6T 1845). ABATE completely ignores (and apparently hopes the Commission will too) Mr. Chreston's lengthy prior discussion explaining that to the extent that the TCJA does affect the retirement analysis, it further weighs in favor of retiring the Tier 2 coal units.[24] Specifically, Mr. Chreston testified in part:

> "The difference between the retirement analysis, for instance as an example, we compared our proposed, installing the proposed project or retiring the existing coal units. 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 of capital and deferred taxes, that ***the heavy capital utilization for the proposed project would be more affected by 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***

[24] The River Rouge, St. Clair, and Trenton Channel power plants are sometimes called "Tier 2" units, in reference to the Company's two-tiered maintenance and capital expenditure allocation strategy. The Company's efforts to maintain overall Fossil Generation availability places priority on maintenance expenditures for the Tier 1 (Monroe and Belle River plants), while minimizing long-term expenditures at the Trenton Channel, River Rouge and St. Clair plants; however, all necessary work to safely operate the units and comply with legal and regulatory requirements will be completed.

> ***analysis, it would be more favor for the proposed project than keeping the Tier 2 units in place***" (6T 1844-50. Emphasis added).[25]

ABATE's suggestion that the Commission must rule on ABATE's proposed findings of fact similarly lacks merit, and ABATE's reliance on MCL 24.285 is misplaced (ABATE Initial Brief, pp 14-15). The statute relevantly states: "If a party submits proposed findings of fact that would control the decision or order, the decision or order shall include a ruling upon each proposed finding." To the extent that ABATE's proposed findings may be true (such as the TCJA reducing the federal corporate income tax), they fail to make any point that is even relevant, let alone controlling, with regard to a final decision in this case. Tax law changes affecting numbers do not preclude a Commission decision as ABATE suggests; instead, the numbers shift further in support of DTE Electric's proposals in this case, and therefore in further support of a Commission decision approving those proposals.

DTE Electric previously explained that it is required to demonstrate compliance with its Planning Reserve Margin Requirement ("PRMR"), which is the Company's forecasted bundled peak demand (coincident with the MISO's peak demand) plus the required Planning Reserve Margin ("PRM").[26] In 2022, the Company estimates a PRMR of 10,744 MW (6T 1605, 1719-20; 7T 2228; Exhibit A-4 2nd Revised, page 98). There is also a Local Clearing Requirement ("LCR")

[25] The TCJA similarly favors the Proposed Project as compared to renewable resources. Mr. Chreston explained, for example: "I haven't run specific numbers, but the fact that renewables tend to be shorter depreciation, tax depreciation, usually five years is how we have treated them, versus our gas plant that's over a longer 20-year period, the deferred tax impact actually doesn't favor renewables as much as the proposed project" (6T 1851-52).

[26] Each year, the Midcontinent Independent System Operator ("MISO") establishes a PRM, which is the amount of capacity above the weather-normalized peak demand to reliably serve load. Per the MISO Business Practice Manual ("BPM"), "Local Reliability Requirements for each LRZ will be determined by MISO through engineering studies based on the 0.1 days per year loss of load expectation (LOLE) criteria for each LRZ in isolation" (Exhibit A-50). The resulting Local Reliability Requirement ("LRR") is the amount of resources needed by that LRZ to reliably meet its forecasted peak load before considering imported capacity (7T 2227, 2243).

because a certain amount of capacity must be located near the load due to the limitation of the transmission system to import additional capacity (7T 2229).[27] Because both the PRMR and LCR are enforced in the MISO PRA, the amount of imported capacity that is cleared to meet the PRMR cannot exceed the difference between the PRMR and LCR. DTE Electric refers to this difference as the Effective Capacity Import Limit ("ECIL"), which is mathematically denoted as follows: PRMR – LCR = ECIL (7T 2244).

Some parties have indicated confusion regarding the term "ECIL," which is not defined by MISO (*e.g.*, AG Initial Brief, p 9, reflecting testimony by AG witness Mr. DiDomenico. See also MEC/NRDC/SC Initial Brief, p 73). However, Ms. Wojtowicz explained that ECIL is a calculation that directly results from MISO's application of the PRMR and LCR constraints in the PRA auction clearing process. Resources are constrained in the auction clearing process by ensuring that sufficient local resources are cleared to meet the LCR, then clearing additional resources in economic order up to the PRMR. The MISO Business Practices Manual (BPM) provides, "The annual PRA…shall clear ZRC [Zonal Resource Credit] offers in order to satisfy 100% of the PRMR for each LSE [Load Serving Entity]" (Exhibit A-51). The MISO BPM further states, "MISO will use the offers in conjunction with the import and export constraints, local clearing requirements, and other inputs to determine the least cost set of offers that respects the various constraints" (Exhibit A-52). Thus, both the PRMR and LCR are enforced in the PRA, so

[27] In addition to calculating the LRR, MISO performs a transfer analysis to determine the Capacity Import Limits ("CIL") and Capacity Export Limits ("CEL") of each Local Resource Zone ("LRZ," the Company's service territory is in LRZ 7), along with the Local Clearing Requirement ("LCR"), which is the minimum amount of unforced capacity (the amount of capacity assigned to a resource utilizing historic availability) that must be physically located within a LRZ while fully utilizing the LRZ's CIL. Both the LCR and CIL must be enforced in the PRA to ensure a zonal reliability of 1 day per 10 years LOLE, so the actual amount of capacity that a LRZ can import can be constrained more than the CIL, resulting in an effective CIL ("ECIL"). MISO's Planning Resource Auction ("PRA") Auction Clearing Price ("ACP") will be set to the Cost of New Entry ("CONE") when there is insufficient capacity to meet the LCR of a zone, or the total PRMR for the MISO footprint (6T 1725; 7T 2229, 2241-43).

the amount of imported capacity that is cleared to meet the PRMR cannot exceed the difference between the PRMR and LCR (7T 2244-45).

Accordingly, suggestions such as "the Commission should disregard the Company's unjustified ECIL constraint and explore resources external to LRZ 7 as possibilities" (AG Initial Brief, p 10) merit no serious consideration. ECIL is not a "constraint" by the Company. It is straightforward calculation reflecting how MISO works. This must be accounted for instead of being disregarded due to an apparent lack of understanding. It is similarly pointless to explore "possibilities" that ultimately must yield to the reality of how MISO works.

The AG similarly suggests that an LRZ can import up to the CIL without violating any resource adequacy or transmission system reliability standards (AG Initial Brief, p 9, reflecting testimony by AG witness Mr. DiDomenico). However, Ms. Wojtowicz explained that this suggestion reflects a lack of understanding regarding how MISO implements its resource adequacy rules. Physical power can be imported into a LRZ up to its CIL without violating resource adequacy standards; however, by first enforcing the LCR and then only the PRMR (as opposed to the LRR) during the PRA, the full CIL is not utilized while clearing resources in the PRA (7T 2246; Exhibit A-53).

DTE Electric's IRP indicates that the Company will require 472 MW of additional capacity to meet its projected PRMR beginning in 2022 (the PRMR forecast of 10,744 MW minus Total Planning Resources of 10,272 MW). This shortfall grows to 1,266 MW in 2023 after the announced coal plant retirements are complete (6T 1718-21; Exhibit A-4 2nd Revised, page 99).[28] As indicated above, the eight (now seven) units planned for retirement include: River Rouge Unit 3, St. Clair Units 1- 3,[29] St. Clair Unit 6, St. Clair Unit 7, and Trenton Channel Unit 9. In total, these units contributed ~ 1,822 MW of capacity toward the Company's PRMR in Planning Year 2017 as shown on Exhibit A-27 (sum of unit's unforced capacity ("UCAP") (6T 1606).

MISO's LRZ 7 (which is the region that includes DTE Electric's service territory) currently does not have sufficient capacity to meet its PRMR without relying on imported capacity from the rest of the MISO regions (7T 2231; Exhibits A-24, A-25, and A-26). There are constraints to the amount of capacity that can be imported into LRZ 7 (the ECIL was approximately 1,200 MW in Planning Year 2017-2018 and projected to drop to approximately 1,000 MW in Planning Year 2023-2024) and a continuing risk of shutdown (by choice due to economics, or forced due to the aging generation fleet) of a sizable amount of existing MISO capacity outside of LRZ 7 that could potentially be imported (7T 2230-31). Therefore, 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 (6T 1724-25; 7T 2231).

It is reasonable and prudent for DTE Electric to secure a reliable supply of energy for its customers. MEC/NRDC/SC respond with a flurry of alleged possibilities, with little explanation

[28] The Company's IRP outlines expected resource additions and reductions over a period of time and estimates the revenue requirements associated with operating these resources over that time period. The resource additions reflected in DTE Electric's 2017 IRP do not represent specific and unique physical generating assets or demand side resources. Rather, the resource additions reflected in DTE Electric's 2017 IRP are described in more general terms of timing, size, technology or resource type, and desired operating characteristics. The term "generic unit" is used to represent these resources in IRP modeling (6T 1605-1606).

[29] It should be noted that the figures referenced in this discussion include St. Clair Unit 4 that was retired during this proceeding.

and no analysis (*e.g.*, MEC/NRDC/SC Initial Brief, pp 58-76),[30] apparently hoping that the sheer volume of distractions will move the Commission towards their agenda (opposing the burning of any fossil fuels) where electric reliability is irrelevant. For example, they suggest that a firm capacity purchase from outside of LRZ 7 could reduce the Company's PRMR (MEC/NRDC/SC Initial Brief, p 64, citing their witness Mr. Osborn). However, Ms. Wojtowicz explained that the suggestion refers to a Full Responsibility Purchase ("FRP"), which is a purchase that shifts responsibility of load and associated resource adequacy requirements from the purchasing entity to the selling entity. A FRP does not eliminate the resource needs of the shifted load, nor does it move the locational resource requirement to the seller's location. A FRP by the Company would not eliminate LRZ 7's need to meet the LCR; otherwise, no one in LRZ 7 will have reliability that meets industry accepted standards. Furthermore, the Company is responsible for the reliability of its customers' electric service and would not shift that responsibility to another entity by entering a FRP (7T 2246-47).

There are also multiple flaws in MEC/NRDC/SC's alternative analyses. First, the premise that there are no resource-adequacy concerns in the MISO market is significantly flawed because it is apparently based on a misunderstanding (or choice to ignore) the LCR, which is the amount of local generation needed to ensure reliability as determined by MISO. There is also a risk with the ongoing performance of the existing aging generation fleet within MISO, as reflected by worsening MISO system-wide weighted forced outage rates, which have been contributing to

[30] It is well-settled law in Michigan that it is not sufficient for a party to simply announce a position or assert an error and then leave it up to the court to discover and rationalize the basis for its claims, or unravel and elaborate for him his arguments, and then search for authority either to sustain or reject his position. *Wilson v Taylor*, 457 Mich 232, 243; 577 NW2d 100 (1998), citing, *Mitcham v Detroit*, 355 Mich 182, 203; 94 NW2d 388 (1959).

increases in the PRM requirement that will likely continue. The Commission has indicated similar concerns, stating for example that:

> "***The Commission remains concerned that LSEs in the Lower Peninsula do not have adequate capacity to meet the planning reserve requirements***. Thus, in the near term, the regional supply outlook is critical when assessing our situation because LSEs in Zone 7 still need to rely on imports from out of state to meet the minimum required reserve margin. Supplies at the regional level have increased since last year, but ***it is highly likely that Michigan will need additional capacity resources within the state, due to additional expected retirements, to meet the LCR in coming years***" (July 31, 2017 Order in Case No. U-18197, p 8. Emphasis added).

Reliability is a paramount consideration in the present legal environment under newly-enacted Act 341 and a changing landscape of plant availability in MISO Zone 7 due to outages and retirements of aging dispatchable coal plants. The Commission has observed, for example: "Section 6w [of 2016 PA 341 or "Act 341"] established a ***new framework for resource adequacy in Michigan – that is, ensuring electric providers can meet customers' electricity needs over the long term even during periods of high electricity consumption or when power plants or transmission lines unexpectedly go out of service***" (September 15, 2017 Order in Case No. U-18197, p 5). The Commission also recently observed that it is "***well aware how these [capacity] projections can change abruptly and significantly based on load forecasts and generator availability***" (September 15, 2017 Order in Case No. U-18197, p 40. Emphasis added).

The Proposed Project needs to be commercially available by June of 2022 to meet the Company's summer peak load requirement in 2022. MISO's compliance requirements including a generation verification test must be completed by March of 2022. To achieve these dates, construction is planned to begin in the spring of 2019.[31] Much has to be done before construction

[31] Mr. Weber provided additional detail regarding the four phases of MISO planning, and the schedule of payments related to transmission upgrades identified in the Definitive Planning Phase ("DPP") of the MISO Large Generator Interconnection Agreement ("LGIA") procedure (7T 2162-63; Exhibit A-34).

can begin and there is a relatively short time to complete engineering, construction, and commissioning activities (8T 2605-2606; Exhibit A-42).

ABATE's suggestion that there would be no time problem with requiring the Company to refile its case in conformance with new MCL 460.6t IRP filing requirements (ABATE Initial Brief, p 13) is frivolous in light of the record. Anybody who has ever dealt with construction (or applies common sense) also knows that delays are problematic. ABATE's suggestion is also unlawful as discussed in section IV of DTE Electric's Initial Brief and above regarding the Company's compliance with applicable filing requirements in this case.

This is the first case under the newly-revised CON statute, but guidance is provided by other cases concerning the need to construct utility projects. For example, in granting ITC a certificate of public convenience and necessity ("CPCN") for the construction of a transmission line under 1995 PA 30, MCL 460.561 *et seq*., the Commission recognized that the need issue must take into consideration the time required to construct utility infrastructure, and necessarily be based on projections and extrapolations of data:

> "In reviewing the need issue, it is important to understand that need in the electric utility business is much different than need in the ordinary sense of the word. In individual day to day lives, planning to meet a routine need is not a long and drawn out process. However, an electric utility cannot simply visit a building supply company, order hundreds of utility poles and miles of wire, and start construction on its project. The utility or transmission company building to meet its needs must obtain permits, approvals, and rights of way. There are engineering issues to be considered. Construction supplies and crews must be arranged. All of these activities take time. This case is an excellent example. It has taken the parties and the Commission one year to reach a final determination. Accordingly, much of the support for such long term projects must necessarily be based on projections and extrapolations of data. The Commission finds that such data exists in the record and it supports a finding of need for the new line" (May 31, 2007 Order in Case No. U-14861, p 31).

It also bears emphasis that the need for power is not just an abstract concept without real world consequences. It concerns the supply of ***reliable*** power to customers. There is a cost to customers if power is lost. Hence, there is a need to construct utility infrastructure to address a reliability issue.[32]

Based on the discussion above and in DTE Electric's Initial Brief, the preponderance of the evidence shows that there is a need for replacement power to be supplied by the Proposed Project to fill the significant gap between DTE Electric's customers' demand for electricity and DTE Electric's resources to supply that electricity, which begins in 2022 (472 MW) and quickly grows in 2023 (to 1,311 MW) caused primarily by planned coal plant retirements. Therefore, the Commission should issue a CON under MCL 460.6s(3)(a) that the power to be supplied by the Proposed Project is needed.

VI. THE PREPONDERANCE OF THE EVIDENCE SHOWS THAT THE PROPOSED PROJECT'S DESIGN CHARACTERISTICS REPRESENT THE MOST REASONABLE AND PRUDENT MEANS OF MEETING FUTURE POWER NEEDS.

DTE Electric's Initial Brief, pp 28-33, presented an overview of how the Proposed Project satisfies MCL 460.6s(4) (c) and (d)'s requirements, and why the Company's request for an MCL 460.6s(3)(b) CON should be granted. Staff agrees and "recommends the Commission grant DTE's request for approval of the 'Certificate of Necessity that the design characteristics of the proposed electric generating facility or investment in an existing generation facility or the terms of a power purchase agreement represent the most reasonable and prudent means of meeting future power needs.'" (5T 185-86. See also, Staff Initial Brief, pp 1, 7, 50, recommending that the Commission approve DTE Electric's three requested CONs). The AG similarly states that "the Commission can reasonably find that DTE Electric showed that the Proposed Project was the most reasonable and prudent means of supplying the needed power" (AG Initial Brief, p 10).

The trade association and environmental Intervenors criticize DTE Electric's proposal by using 20/20 hindsight to cherry-pick recent events (after DTE Electric filed its proposal on July 31,

[32] *In re Application of Michigan Electric Transmission Co*, 309 Mich App 1, 9-13 867 NW2d 911 (2014), *aff'd* 500 Mich 98 (2017) (affirming the Commission's July 29, 2013 Order in Case No. U-17041).

2018) and speculate about the future, to vaguely suggest that there might be some other combination of resource options that might somehow be preferable from their self-interested perspective. For example, a national advocate for the solar industry[33] suggests that solar is the answer – starting with the suggestion that the Commission further his agenda through the Public Utility Regulatory Policies Act of 1978 ("PURPA") for the benefit of that witness's constituents. The Commission appears to have recently recognized, however, that its PURPA-market decisions require further consideration (February 22, 2018 Order and Notice of Opportunity to Comment in Case No. U-20095).

It again bears emphasis that DTE Electric presented the only specific proposal to meet the power need discussed above and established on the record. Staff similarly observes that "no alternative proposals were presented to the Commission in accordance with MCL 460.6s(13). (5 TR 210.) Staff can only assume that since no other alternatives were presented to the Commission, no other feasible alternatives are available at this time" (Staff Initial Brief, p 14). The AG similarly recognizes: "Interestingly, it is worth pointing out that no alternative proposal was presented in this proceeding pursuant to MCL 460.6s(13)." (AG Initial Brief, p 17).

There is just one viable proposal to satisfy the (essentially undisputed) need for power. All of the intervenors' criticisms of that proposal fade to nothing in light of the complete failure of anybody to even begin trying to do what they allege could be done. Moreover, all the vaguely-suggested alternatives to DTE Electric's Proposed Project are driven by narrow objectives (*e.g.*, promoting specific industry or policy objectives), which fail to appropriately consider the "most reasonable and prudent means" to supply electricity to DTE Electric's customers. In contrast, the Company is focused on safely, efficiently, and reliably meeting the evolving energy needs of its customers.

[33] Kevin Lucas, the most prolific of Intervenor's witnesses with 220 pages of testimony that he apparently has developed for various regulatory dockets, is "the Director of Rate Design at the Solar Energy Industries Association (SEIA) . . . SEIA is a national trade association for the U.S. solar industry. SEIA works with 1,000 member organizations to advance solar power through education and advocacy" (5T 658).

Accordingly, DTE Electric's 2017 IRP was designed to meet its customers' future generation and capacity needs by creating a portfolio of supply-side and demand-side resources that optimally balances the following six characteristics: (1) Reliability; (2) Affordability; (3) Clean; (4) Flexible and balanced; (5) Compliant; and (6) Reasonable risk (6T 1606-1607; 1715-16; 1813-14).

DTE Electric's 2017 IRP was designed to manage the impacts of currently-known challenges and opportunities, and to position the Company to successfully address future challenges and opportunities as they arise (See generally, 6T 1712-18, 1743-46). Staff further states that: "Keeping in mind the guidance and standards at the time, the Company has met the minimum statutory standard in completing its analysis of the proposed project" (Staff Initial Brief, p 24). The AG similarly states that: "Despite certain flaws in the Company's IRP process, the Commission can reasonably find that DTE Electric showed that the proposed Project was the most reasonable and prudent means of supplying the needed power" (AG Initial Brief, p 10, with argument continuing to page 13 regarding what the AG's witness thought could be "improved upon" for future filings). The AG's witness concluded: "Overall the Company reasonably conducted the IRP and planning process" (6T 1539). With regard to further comments about DTE Electric's March 2019 MCL 460.6t IRP filing (or other future filings), DTE Electric incorporates the discussion in section IV above. For purposes of this case, all of the parties representing the public agree that DTE Electric's IRP satisfies applicable requirements and supports the Proposed Project.

The results of the Company's IRP process indicate that a blend of flexible resources continues to be key in maintaining power reliability while keeping costs low for customers (6T 1607). DTE Electric's 2017 IRP consists of a 1.5% annual savings energy efficiency program, 15% renewable resources by 2021, expanded Demand Response by an additional 125 MW, and an approximately 1,100 MW combined cycle gas turbine ("CCGT") plant in 2022 (6T 1718, 1769; Exhibit A-4 2nd

Revised, p 26; Exhibit A-6, 2017 DTE Electric Integrated Resource Plan).

The IRP report (Exhibit A-4 2nd Revised) details how the Company's analysis identified the most reasonable and prudent means to meet the projected resource requirements through 2040. The size and timing of the Company's expected resource requirements was based on: (1) forecasts of how the Company's existing generating assets would operate until their planned retirement dates; (2) expected generating additions such as renewables and Ludington Pumped Storage upgrades; (3) forecasted impacts of energy efficiency and demand response programs; and (4) forecasts for demand and energy sales (6T 1607).

In developing the IRP, the Company considered five portfolio scenarios,[34] each of which had different market futures with respect to fuel prices, CO_2 regulations, and new unit cost curves. In addition, eight sensitivities[35] were applied to the scenarios to study the effects of different levels of load growth, renewable energy additions, energy efficiency, technology assumptions including size and cost, Electric Choice capacity requirements, and CO_2 regulation assumptions (6T 1607-1608, 1773-38; Exhibit A-8).

A comprehensive IRP process takes considerable time to develop and implement. The modeling for the five IRP scenarios was done from June 2016 through February 2017. Shortly before filing this case, the Company also evaluated the impact of known changes to assumptions used in the IRP by running the "2017 Reference Scenario" (See Exhibit A-4 2nd Revised, section 12.2). Inputs updated from the Reference Scenario include the market prices, load forecast, and the fuel prices, as

[34] Scenarios are futures that affect market and commodity prices on a broad basis (6T 1733). The five scenarios that were completed as part of the IRP are: (1) Reference; (2) High Gas Prices; (3) Low Gas Prices; (4) Emerging technology; and (5) Aggressive CO_2 (6T 1734-35; Exhibit A-4 2nd Revised, pp 23-24, and section 11).

[35] Sensitivities are more Company-specific variables that only affect the DTE Electric service territory and/or Michigan (6T 1733-34). The eight sensitivities are: (1) Load; (2) Renewable Energy; (3) Energy Efficiency; (4) Combined Cycle Capital Costs; (5) Combined Cycle sizing; (6) Electric Choice Customer Return; (7) CO_2 reduction; and (8) New Nuclear (6T 1735-37; Exhibit A-4 2nd Revised, p 24, and section 11).

well as the latest Energy Efficiency plan and Renewables plans. The results of the 2017 Reference scenario fell within the boundaries of the previously-run scenarios and sensitivities, thereby confirming that the selection of a 1,100 MW combined cycle unit remains reasonable and prudent when known changes are taken into account (6T 1608, 1738-39, 1762-63).

Various criticisms have been made with regard to the Company's modeling by suggesting that different results are plausible if one uses different inputs based on changing conditions coupled with further speculation about the future. Such criticisms unrealistically presume that any model can predict the future with certainty. In contrast, the Company used a variety of scenarios and sensitivities to reflect a range of possible futures and performed three forms of risk analyses to "stress test" modeling assumptions. The end result is that even with changes to factors, the Company's combined cycle technology was still the most reasonable and prudent plan. The future is inherently uncertain and the Company does not expect either the original Reference Scenario or the 2017 Reference Scenario to exactly predict it. The Company considers these two scenarios and the numerous variations of scenarios and sensitivities to represent rational and feasible outcomes given what was known when the modeling was done. The Company's goal in running all of these cases, scenarios, and sensitivities was to select the most reasonable and prudent long-term solution to address the Company's forecasted resource requirements in energy and capacity while considering multiple possible futures (6T 1608).[36]

The results of the IRP process indicate that in the vast majority of the cases modeled, the Company's expected resource requirements for energy and capacity would most prudently be addressed by the addition of a base-load combined cycle gas turbine generating plant sized at

[36] Moreover, the Legislature's directive to decide CON cases in 270 days reflects an intent for timely decision making. Nothing would ever get decided or built if one were continually locked in a planning process requiring further consideration of additional data or alternative analyses.

approximately 1,100 MW with demand response and minor market purchases or other resources up to 300 MW being used to make up any remaining energy and capacity needs (6T 1609, 1756).

In addition to DTE Electric's IRP modeling efforts, the Company launched processes to assess possible build projects or purchase opportunities. To assess a possible build project, the Company conducted a siting study (Exhibit A-39) that considered locations both at existing power plant sites and at green-field sites (5T 1464-65; 6T 1609). The Company concluded the best site for a build project would be near the Company's existing St. Clair and Belle River power plants. The site is an ideal location because it is close to three natural gas pipelines and multiple 345 kV transmission lines and its proximity to existing Company-owned power plants allows for additional synergies (5T 1465-69, 1471; 6T 1609; 8T 2553-56; Exhibits A-40 and A-41).

With that information, the Company issued Requests for Proposal ("RFPs") seeking competitive bids for combined cycle gas turbine technologies and Engineer Procure Construct ("EPC") services to build a combined cycle natural gas plant of about 1,100 MW near the Company's St. Clair and Belle River power plants (6T 1609-10). Around the same time, the Company issued an RFP to assess market-based alternative options from third parties (6T 1610), as further discussed below.

Based on the results of those RFPs, the Company proposes to construct an approximately 1,100 MW natural gas fired combined cycle facility located on Belle River Power Plant's property, at a total projected installed capital cost of $989 million (6T 1610). Additional details are addressed below in the context of applicable discussions.

A. Description of the Proposed Project.

DTE Electric's Initial Brief, pp 34-38, explained the Company's proposal to construct a nominal 1,100 MW, multi-shaft 2x1[37] combustion turbine combined cycle power plant on the Belle River Power Plant's property, at a total projected installed capital cost of $989 million (6T 1610; 8T 2608; Exhibit A-43). Exhibit A-44 shows the estimated timing of the capital spending (8T 2609). DTE Electric's cost estimates did not materially change, so DTE Electric did not file a 150-day cost update.[38] In addition, electric transmission upgrades to the ITC Network Transmission System ("NTS") are estimated to cost approximately $29 million (7T 2163-64; 8T 2608; Exhibit A-35), and will be recovered separately by ITC (7T 2166-67).

There appears to be no dispute about the Proposed Project's location, which is ideal from a natural gas supply perspective due to its proximity to existing natural gas infrastructure and market hubs (8T 2553-56). Staff specifically recognizes that the location is favorably near existing natural gas and transmission infrastructure (Staff Initial Brief, pp 48-50).

The Proposed Project will use Advanced Class natural gas combustion turbine technology representing the most efficient power generation technology in the market today. This technology is also technically and commercially viable (5T 1470, 1475-76).[39] The plant will also include best available control technology ("BACT") for air emissions. Combined cycle generation is highly reliable and offers significant operating flexibility while maintaining compliance with permitted air emissions limits. The Proposed Project is planned to be the Company's most efficient generating

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[37] 2x1 refers to a configuration where two gas turbines are installed with a single steam turbine.

[38] MCL 460.6s(4)(c) relevantly states: "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."

[39] ELPC witness Beach suggested a concern that DTE Electric is proposing to use a new class of advanced turbines, for which there is little operating experience. Mr. Damon explained that there is significant operating experience, and that the 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 each progression of advanced gas turbine building upon technology used in earlier model gas turbines, and maintaining consistently high reliability and availability (5T 1482-83; Exhibit A-72).

station with a design service life of 30 years, which is consistent with that of other large frame natural gas combined cycle generating stations (5T 1470-72).

The Company's Major Enterprise Projects ("MEP") organization will manage the Proposed Project's construction. MEP's extensive experience and expertise in managing large and complex projects, as well as the contracting strategy discussed below, provide a high level of confidence that cost and timing estimates will be achieved (8T 2611-12). If the CONs are approved, then DTE Electric will provide status reports to the Commission including cost and schedule updates as required by MCL 460.6s(7).[40] (8T 2613).

Staff agrees that the Company will comply with statutory filing requirements (Staff Initial Brief, p 17). Staff further suggests biannual review filings with cost and schedule updates. There appears to be no dispute on this matter.

In accordance with MCL 460.6s(4)(c) (quoted above), the estimated costs for the Proposed Project were developed through the competitive bidding process for both the power island equipment ("PIE") and EPC contract. This contracting strategy ensures that the Proposed Project's estimated cost is reasonable and that the Proposed Project is the most reasonable and prudent means to fill the Company's need for power (8T 2606-2608).[41] Staff states that the Company "demonstrated to Staff that it used a competitive bid strategy to contract its proposed project" (Staff Initial Brief, p 12, with discussion continuing to page 14).

[40] MCL 460.6s(7) provides: "The utility shall annually file, or more frequently if required by the commission, reports to the commission regarding the status of any project for which a certificate of necessity has been granted under [MCL 460.6s(4)], including an update regarding the cost and schedule of that project."

[41] In November of 2016, the Company initiated a formal RFP process for the PIE, which includes the technology selection and purchase of the Combustion Turbine Generators, the Heat Recovery Steam Generator ("HRSG"), the Steam Turbine generator, and the Distributed Control System ("DCS"). In March of 2017, the Company initiated a similar RFP process for EPC services, and has requested both BOP pricing as well as full-wrapped EPC Lump Sum Turnkey ("LSTK") pricing (8T 2609; Exhibit A-42).

The Company assumed a 6% contingency, which was developed through a risk evaluation process that is consistent with good practices established by the Construction Industry Institute ("CII"), the Project Management Institute ("PMI"), and the Association for Advancement of Cost Engineering ("AACE") (8T 2611). The AG suggests that contingency costs should be disallowed because MCL 460.6s(9) does not specifically mention them (AG Initial Brief, pp 18-19). However, the AG's suggestion lacks sound foundation because MCL 460.6s(9) concerns cost recovery. This case instead concerns cost planning. Applicable case law reflects that contingency costs are reasonable costs to include in the cost estimate within the Company's CON application under MCL 460.6s(6), which represents an "up-to" amount approved for recovery under CON guidelines. [42]

Staff suggests that a 1.9% contingency ($17.8 million) should be sufficient (Staff Initial Brief, pp 47-48; 5T 205), and the AG supports this amount in the alternative (AG Initial Brief, p 19). See also Staff Initial Brief, pp 6-7 ("Staff recommends that the Commission preapprove $951.8 million of the requested $989 million for DTE to build an 1100 MW NGCC plant at its Belle River location. This amount is the Company's request minus contingency amounts that should be disallowed").

DTE Electric disagrees that Staff's suggested contingency reduction is reasonable considering the scale, scope and complexity of the Proposed Project. Staff states that it "believes that there should be very little contingency needed" where the Proposed Project "is expected to be built as a *full-wrap* EPC project with a *fixed-price* contract" (Staff Initial Brief, p 47. Emphasis in

[42] See *In re Application of Indiana Michigan Power Company for a Certificate of Necessity*, 307 Mich App 272, 295; 859 NW2d 253 (2014), vacated in part on other grounds, appeal denied in all other respects, 498 Mich 881 (2015); October 25, 2017 Order in Case No. U-18224, p 106.

original). However, the record instead reflects that DTE Electric's contingency level is consistent with HDR Engineering, Inc.'s ("HDR")[43] firsthand knowledge working with utilities entering into fixed price full wrap EPC contracts, which indicates that holding an Owner's contingency in the range of 5% to 6% with total project contingency in the range of 10% is typical at this point in the project life cycle (5T 1478-81). Mr. Damon also disagreed with Staff's suggestion to eliminate $12 million relating to line 19 of the original risk register based on an alleged "lack of adequate planning" (5T 204-205), explaining in part: "HDR has been engaged with DTE Electric for nearly three years developing the project and during this time it has been clear that DTE Electric has consistently followed prudent industry practices with regard to planning, procedures, and processes to mitigate these risks . . . 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. It is customary and rational to identify improvements during project execution to enhance parameters such as life cycle costs and reliability of the facility." (5T 1480)

B. Load and price forecasts.

DTE Electric's Initial Brief, pp 38-45, discussed the load forecasts that were used in the IRP process, which are Reference Scenario, High Load Sensitivity, Low Load sensitivity, and 2017 Reference Scenario (See generally, 8T 2405; Exhibit A-4 2nd revised).[44] Staff testified that in its "opinion, the Company's projected load growth expectations in the various scenarios are

[43] DTE Electric selected HDR to provide Owner Engineer ("OE") services.

[44] The forecasts used in the Reference Scenario, High Load Sensitivity, Low Load sensitivity were based on actual data through February of 2016. The forecast used in the 2017 Reference Scenario was based on actual data through October of 2016 (8T 2405). Mr. Leuker also further explained the assumptions used in the High Load Sensitivity, Low Load sensitivity, and 2017 Reference Scenario (8T 2419-20).

appropriate" (5T 227). Staff's Initial Brief similarly states: "Staff determined that the long-term load forecast growth rates were consistent with other load growth projections in the region" (Staff Initial Brief, p 18).

MEC/NRDC/SC suggest that DTE Electric's proposed course of action is confusing and inconsistent based largely on Exhibit A-10 (MEC/NRDC/SC Initial Brief, pp 17-20). MEC/NRDC/SC's suggestion speciously criticizes the form of information, while ignoring its substance, despite Mr. Chreston's explanation when he began discussing the exhibit:

> "Well, you know to be honest, the Commission had some guidelines for IRP and they had some sample kind of ways of displaying information. And I think they said it could be illustrative or use something like this. And so we tried to adopt what we thought was a good way to present information, and trying to get all the IRP information into this. Obviously since it's now the Third Revised, we have struggled with trying to make it readable and still get to the spirit of what we thought the Commission was looking for, for particular information. So you know, we turned over a lot of work papers and exhibits to try to give everybody all the needed information, and putting it in this form was probably not our first choice. But with that caveat, we can proceed with questions" (6T 1863-64).

In response to MEC/NRDC/SC's further allegations and innuendo about the numbers in Exhibits A-10 and A-17 not matching, the short answer is that 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**. The more detailed answer (to the extent the Commission may be interested) is that the two Exhibits have different purposes. Exhibit A-17 reports the Load forecast while Exhibit A-10 reports output of the Modeling of the DTE Proposed Plan as specified by the 2008 PA 286 IRP filing Guidelines, Section H (see pages 268-69 of Staff's Initial Brief and attachments). Therefore, these two Exhibits depict two entirely different representations of the peak demand. There are two main differences between the two Exhibits, which are (1) with Energy Efficiency vs. without Energy Efficiency, and (2) Bundled Load vs. Service Area Load. Exhibit A-10 shows the 2017 Reference

Bundled peaks with 1.5% Energy Efficiency taken out while Exhibit A-17 shows the 2017 Reference Service Area peaks with the 1.5% Energy Efficiency embedded. On Exhibit A-10, line 1 is labeled, “Expected Annual Peak Demand (Without Plan).” The “Without Plan” means that the Energy Efficiency peak impact has been taken out, which has the effect of raising the peak as Energy Efficiency impact is maxed out in the year 2030. The difference between the Bundled Peaks shown in Exhibit A-10 and the Service Area Peaks shown in Exhibit A-17 is the amount of peak attributable to Electric Choice, which is approximately 940 MW in all years in the 2017 Reference Scenario. The above explanation also holds true for the Customer Energy Requirements expressed in GWH discussed on pages 18-19 of MEC/NRDC/SC’s Initial Brief.

Given the number and complexity of calculations in this case, it is not surprising that DTE Electric’s witnesses could not recall this level of detail off the tops of their heads under cross examination. This case is not a memory test or a game to reward trial tactics.[45]

MEC/NRDC/SC witness Mr. Neme suggested that DTE Electric’s sales forecast is too high, so it should be reduced based on his calculated adjustment to energy efficiency embedded in the forecast. However, Mr. Leuker explained that Witness Neme’s “corrected analysis” is not realistic or credible, so it should be disregarded (8T 2423-35). In summary:

1. DTE Electric ran calculations using Mr. Neme’s recommended “reconstituted” sales methodology model, adjusted for DTE Electric market conditions and energy efficiency. This approach produced a higher forecast for residential sales and total sales than the 2016 Reference Scenario (8T 2423-2429, 2434; Exhibit A-48).
2. If Mr. Neme’s “corrected analysis” were valid, then DTE Electric’s Reference Scenario

[45] It is worth noting that the evidentiary record exceeds several thousand pages and includes over 400 exhibits. Furthermore, the evidentiary record is only a small part of the total amount of information exchanged in this proceeding as a result of the approximately 1,700 discovery requests that both Staff and the intervenors’ served upon DTE Electric.

forecast should have been too high. Instead, the opposite occurred. Actual temperature-normalized sales results for 2016 and 2017 (forecasted years in the 2016 Reference Scenario) were higher than forecast in the 2016 Reference Scenario, and higher than Witness Neme's adjusted forecast based on his "corrected analysis" of embedded energy efficiency (8T 2424, 2429-30, 2434).

3. DTE Electric's 2016 Reference Scenario forecast is in line with independent third-party load forecasts from both the EIA and MISO for the East North Central Region and State of Michigan, respectively. In contrast, Witness Neme's "corrected" analysis, when subtracted from the 2016 Reference Scenario forecast, is a clear outlier (8T 2424, 2431-34; Exhibit A-49).

Mr. Neme provided his flawed adjustments to Mr. Evans who relied on that flawed analysis as an input to his models. Therefore, Mr. Evans' models are similarly flawed (8T 2435).[46]

Notwithstanding Mr. Neme's flawed adjustments, Mr. Swiech provided delivered fossil fuel price forecasts for each existing generation facility and fuel type for the IRP process (8T 2550; Exhibits A-28 and A-29. See also 1739-40). The Proposed Project's annual delivered fuel cost is forecasted to range from $3.24 to $7.57 per MMBtu from 2022 through 2040 (8T 2555; Exhibit A-30). This forecast relies on the Belle River Peakers as a proxy for the variable fuel costs, estimated annual fuel costs of $15.7 million for transportation, and $4.5 million for storage (8T 2555). DTE

[46] Staff's reliance upon Mr. Evans' testimony (e.g. regarding a purported 1.882 billion (NPV) ratepayer savings) for the recommendation "…that the Commission direct the Company to include additional renewable energy in its generation portfolio at an accelerated rate above what is included in the Company's current plans" is misplaced. First, Staff ignores Company witness Mr. Chreston's extensive rebuttal testimony against Mr. Evans' flawed models (6T 1777-1790, 1805-1808, and 1813-1816; Exhibit A-77). Second, Staff's recommendation is premature since this case's scope is limited to approval or denial of the Company's requested CONs. See MCL 460.6s(4). Instead, Staff's recommendation is more appropriate for consideration in DTE Electric's March 2019 MCL 460.6t IRP filing. See MCL 460.6t, *et seq*.

Electric will enter into firm gas supply and gas transportation contracts as needed to ensure electric reliability (8T 2548-49, 2553).[47]

ELPC suggests that DTE Electric did not properly account for fuel price risk (ELPC Initial Brief, pp 29-33). To the contrary, the Company's Henry Hub and MichCon CityGate basis forecasts are reasonable and prudent and the Company has already accounted for gas price uncertainty by analyzing a high gas price scenario (8T 2565).[48] ELPC witness Mr. Beach questioned DTE Electric's forecast of Henry Hub prices, but that forecast has proven historically accurate, is consistent with other industry projections, and is the same methodology that DTE Electric uses in PSCR proceedings (8T 2559-61).

There is similarly no merit in Mr. Beach's questioning of DTE Electric's forecast of the MichCon CityGate basis. Again, the process used for this forecast is consistent with the methodology used for the natural gas forecasts in the Company's annual PSCR Plan filings. In addition, the futures market is active on a daily basis, so it is constantly being updated with the current expectations of the market participants. Mr. Beach speculated that higher historical prices may return, but neglects that the decline of the MichCon CityGate basis is driven by real market

[47] For example, DTE Electric entered into a Precedent Agreement with NEXUS Gas Transmission to provide firm natural gas transportation starting upon the pipeline's in-service date. The Precedent Agreement provides for NEXUS to provide 30,000 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 nearby Utica/Marcellus shale region because it has new and growing production, with substantial supply and competitive pricing. Prices for natural gas from this region are expected to remain among the lowest in the country for the foreseeable future. NEXUS will deliver gas from the Utica/Marcellus shale region to MichCon CityGate (Willow Run/Ypsilanti). These NEXUS deliveries will offset DTE Electric's need to purchase MichCon CityGate gas to supply its plants (8T 2549).

[48] Staff suggested a concern about the high gas case, which appeared to be based on inaccurate calculations (6T 1817-18). Staff explains its calculations, and maintains that it is correct (Staff Initial Brief, pp 18-19). The issue deserves no further discussion, since Staff and the Company agree on the ultimate conclusion in any event. Moreover, even assuming one outlier sensitivity indicates some fuel cost risk, the preponderance of all scenarios and sensitivities still selected the Proposed Project.

Staff further suggests that the Company should update its high gas price sensitivity for its March 2019 MCL 460.6t IRP filing (Staff Initial Brief, p 20). DTE Electric incorporates the discussion in section IV above regarding how the Company will proceed appropriately next year.

changes, specifically the dramatic growth of production in the Utica/Marcellus shale region and the increasing transportation capacity between that region and the Midwest (8T 2561-63; Exhibit A-65). Although DTE Electric's MichCon CityGate basis forecast is lower than the PACE forecast, it is similar to the April 2017 IHS forecast and higher than the ICF 2017 Q3 Natural Gas Strategic Outlook (8T 2563; Exhibit A-66).

Mr. Beach further suggested that DTE Electric could contractually eliminate all price uncertainty for $86 million per year, which would increase the Proposed Project's cost by 25%. However, Mr. Beach's suggestion is unreasonable, imprudent, and apparently conceived simply as a mechanism to increase the Proposed Project's costs. DTE Electric has already appropriately addressed long-term gas price uncertainty. The High Gas Price Scenario analyzed gas prices that are more than 40% higher than the Reference Scenario, yet the Proposed Project remains the most reasonable and prudent (6T 1734, 1753; 8T 2464-65). There is similarly no merit in Mr. Beach's use of apparently arbitrary assumptions and flawed math to suggest that the Company's commitment to NEXUS would increase the Proposed Project's costs (8T 2565; Exhibit A-67).[49]

For utility-scale wind costs, the Company's IRP process used 2016 actual installed costs of $2,150/kW and the base with those costs de-escalating based on the Company's best estimate of market costs and assumptions around turbine technology platforms (8T 2473; Exhibit A-22).[50] Operations and maintenance ("O&M") costs are estimated to be $16/kW annually and capital maintenance costs are estimated to average $20/kW annually with both costs assumed to escalate

[49] AG witness DiDomenico indicated (but the AG did not pursue in his Initial Brief) a number of concerns about NEXUS that appeared to be based on misunderstandings that Mr. Swiech corrected and clarified (8T 2566-70). Mr. DiDomenico also appeared to be unaware that the Company is required to file a fuel plan in annual PSCR proceedings under MCL 460.6j(3).

[50] Mr. Beach "generally accepts DTE's assumed trajectory of the future capital costs of new wind farms" (5T 944), but he incorrectly pulled DTE Electric's forecasted wind installed costs from 2018-23 ahead one year. DTE Electric does not agree with his accelerated forecast (8T 2480).

with inflation. Production tax credits ("PTCs") are assumed to phase out according to Internal Revenue Service ("IRS") rules (8T 2474-75).

The net capacity factor ("NCF") for future wind parks for IRP modeling is 41%, which is an optimistic forecasted NCF for a theoretical wind park in Huron County -- Michigan's best wind resource (8T 2473-74). MEIBC support the 41% NCF that the Company used in IRP modeling (MEIBC Initial Brief, pp 13-14), and the record further reflects that this assumption favored wind energy. Future wind parks will likely have a lower NCF because Huron County is Michigan's best wind resource, but wind parks developed through 2025 can be expected to be located elsewhere due to the Huron County voter referendum and local community resistance in the Thumb region (8T 2474). ELPC witness Mr. Beach used a 38% capacity factor, but DTE Electric's recent experience regarding wind development in the State indicates that reasonable net capacity factors for future projects range from 30% - 34% (8T 2481-82). Staff agrees, suggesting capacity factors in the range of 32 - 35%, which will cause an increase in the LCOE of wind (Staff Initial Brief, p 26).

MEIBC acknowledges that "DTE has experience in wind generation in the State of Michigan and relied on such in its analysis" (MEIBC Initial Brief, p 11), but cites national averages to suggest that DTE Electric's cost of wind resource is too high. In addition to the NCF/LCOE discussion above, Ms. Schroeder explained that the Company used 2016 wind installed costs based on actual projects in DTE Electric's portfolio. These projects were competitively bid and then audited by the Staff. DTE Electric's 2018 installed costs are based on a more recent competitively bid-project. These projects were both competitively bid, audited by the MPSC Staff, and the contracts have been approved by the Commission. Furthermore, DTE Electric's forecasted costs beyond 2018 are below NREL's 2016 and 2017 Annual Technology Baseline (8T 2480-81).

MEIBC further suggests that DTE Electric should "reassess…the opportunities for obtaining more near-term wind energy to take advantage of federal production tax credits" (MEIBC Initial Brief, pp 11-12). However, the record reflects that DTE Electric has already taken a number of actions to take advantage of available PTCs including pulling renewable projects ahead (8T 2486).

For utility-scale solar costs, the Company's IRP process used 2016 actual installed costs of $1,900/kWac as the base, and the utility-scale forecast using the Company's internal subject matter experts' projections that are similar to, but lower than Navigant Consulting's published "U.S. Distributed Renewables Deployment Forecast," Navigant Research, 2016. The forecast was based on both the Company's experience developing solar projects and credible third party forecasts of the utility scale solar industry. Also, the Navigant forecast was the most recent published information from Navigant and it was consistent with other published forecasts (6T 1809-10; 8T 2475, 2479-80; Exhibit A-23 highlights the AC and DC installed costs for future utility scale solar projects).

Criticisms about the number of DTE Electric solar assumptions are misleading and pose the danger of causing the Commission to "lose sight of the forest for the trees." (*e.g.*, MEC/NRDC/SC Initial Brief, 24-26). Mr. Chreston explained that DTE Electric attempted to update its analysis as new information was made available. The updated inputs provide additional sensitivities, which demonstrate the robustness of the Proposed Project (6T 1809).

Michigan's solar resource is one of the lowest in the United States and very seasonal. DTE Electric expects future solar parks to operate at a 20% NCFac based on the Company's experience with fixed-tilt ground-mounted solar installations.[51] O&M expenses were estimated to escalate with inflation. The only capital maintenance assumed is to replace inverters once during each project's lifetime. As with wind resources, PTCs are assumed to phase out for solar resources according to IRS rules (8T 2475-76).

MEC/NRDC/SC complain that "DTE's model includes a solar cost assumption that is more than double the amount identified in IRP" (MEC/NRDC/SC Initial Brief, p 26). It is true that the IRP assumed $23/kW for solar O&M when the correct number should have been $12/kW (6T 1811; Exhibit A-80); however, this error was offset by DTE Electric's overly-optimistic assumptions in other areas. For example, DTE Electric set the degradation of solar panels at 0%, and did not include integration costs for renewables. The overall effect of the offsets is that DTE Electric's solar cost ends up being very close to ELPC's cost (6T 1811-12).[52]

Staff agrees that "it would be hyperbolic to state that DTE's solar and wind capital cost assumptions are vastly out of line . . . The Company mistakenly forecasted $23/kW for Solar O&M in lieu of $12/kW, which Staff agrees could skew the results, but Company witness Chreston explains in Rebuttal Testimony that the Company's solar assumptions were optimistic in other areas. When comparing this to ELPC Beach's solar assumption, the two cost projections are close resulting in a 4.3% difference. (4 TR 1812)." (Staff Initial Brief, p 25). There is also considerable upside risk in solar pricing. See, for example, *Changhou Trina Solar Energy Co, Ltd v United*

[51] ELPC suggests that "the industry has moved on" to tracking systems (ELPC Initial Brief, p 10), but Ms. Schroeder explained in part that "most of the research I have read is based on solar in climates that are best suited for solar and don't have the harsh weather that Michigan has . . . our panels that we have now that are tracking systems, they don't always work, the panels aren't tracking. And so if it's stuck in an area that's not optimal for the sun, it may not perform as well as a fixed-panel system" (8T 2496).

[52] Again, ELPC *et al* includes the Solar Energy Industries Association, so it presumably was motivated to present the best solar numbers that it could.

States International Trade Comm, 879 F3d 1377 (Fed Cir, 2018).

ABATE vaguely suggests that the Commission cannot approve the Proposed Project because the costs of all resource options are unknown (ABATE Initial Brief, pp 10, citing only a dictionary definition of "most"). ABATE ignores that on this record, which must be the basis for the Commission's decision,[53] the Proposed Project "represents the most reasonable and prudent means of meeting the power need relative to other resource options." MCL 460.6s(4)(d). The inquiry is not limited to cost, but instead concerns other criteria, particularly reliability, as discussed in DTE Electric's Initial Brief and this Reply Brief. To the extent that the Commission further considers the TCJA (as ABATE suggests), this additionally favors the Proposed Project as compared to renewable resources. Mr. Chreston explained, for example: "I haven't run specific numbers, but the fact that renewables tend to be shorter depreciation, tax depreciation, usually five years is how we have treated them, versus our gas plant that's over a longer 20-year period, the deferred tax impact actually doesn't favor renewables as much as the proposed project" (6T 1851-52).

MEIBC (Initial Brief, p 10) suggests that the Commission assume that DTE Electric must supply substantial customer-requested renewable energy (5% of its sales from renewables, additional to its renewable energy standard obligations, by 2024, and 10% of its sales by 2029), based in part on Mr. Jester's inaccurate suggestion that no provision for customer-requested renewable generation is evident. To the contrary, DTE Electric actually has 150,000 MWh per year of renewable resources from wind and solar assets currently allocated to a Commission-approved customer-requested renewable energy program in its portfolio of which 93% remains

[53] Michigan's Constitution requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." Const 1963, Art 6, § 28. The APA precludes the Commission from making decisions based on non-record materials. MCL 24.276.

available to subscribing customers (8T 2482-83). Ms. Schroder further explained that MEIBC's proposed assumptions are unrealistic and unsupportable. The rising national trend in customer-requested renewable energy has been driven by corporate purchasers. Mr. Jester also acknowledged that half of all voluntary renewable purchases occur in just five states "that are characterized by retail competition or by state incentives for renewable energy generation" (5T 441). He goes on to say that even in these states with unregulated markets and/or high renewable subsidies, voluntary renewable purchases do not even constitute 5% of sales. Most of the largest corporate renewable energy deals are in areas where corporate buyers can sign a contract for differences and earn a market rate higher than the PPA price. That is not likely to be the case in Michigan over the next decade (8T 2483).

C. DTE Electric appropriately analyzed alternative resource options, including no build, renewable energy, energy efficiency, and demand response.

DTE Electric's Initial Brief, pp 45-59, explained how the Company appropriately considered other electric resources that could defer, displace, or partially displace the Proposed Project, in accordance with MCL 460.6s(11). Some discussion is now restated for context.

First, the Company developed a list of options determined to be commercially viable, and subjected those options to a preliminary economic screening based on levelized cost of electricity ("LCOE") calculations. Options with the highest forecasted cost per megawatt hour were eliminated from further consideration. Next, the remaining options were narrowed further after a benefit versus cost analysis. The technology and resource options that were utilized in the Company's most comprehensive and complex IRP modeling steps include: natural gas combustion turbines, combined cycle gas turbines, renewables (wind and solar), energy efficiency ("EE"), demand response ("DR"), storage, and short-term market purchases of up to 300 MWs (6T 1610-11, 1721-28; Exhibit A-4 2nd Revised, Section 10).

The Company gave due consideration to potential "no build" options. As discussed above, the retiring coal plants will require replacement by the Proposed Project. Even the most aggressive EE and DR alternatives would still leave a substantial shortfall. MISO LRZ 7 lacks capacity and there are significant risks and potentially high costs associated with importing capacity. An analysis of transmission import capacity (further discussed in DTE Electric's Initial Brief and below) demonstrates that it is unlikely that the import capability of the transmission system in Michigan's Lower Peninsula could be expanded in time to offer a realistic alternative to the Proposed Project. The Company also looked at Volt/VAR (volt-ampere reactive) optimization technologies. Ultimately, due to the projected capacity circumstances and the limitations and risks of all "no build" alternatives, the Company concluded that a "no build" option would not be feasible or prudent (6T 1723-28. See also 6T 1802-1803).

The IRP modeled renewables, EE and DR options. A certain level of renewables was considered to be a hard input in each scenario or sensitivity that was modeled while additional levels of renewables were available for selection by the modeling tool. In most cases, the minimum level of renewables included about 175 MW of renewables above the level approved by the Commission's September 23, 2016 Order in Case No. U-18111 (approving DTE Electric's amended Renewable Energy Plan). This level of renewables went beyond 2008 PA 295's mandate for 10% renewable generation that was in effect at the time the modeling runs were completed. For the 2017 Reference scenario, the minimum level of renewables was consistent with the new 15% target established by 2016 PA 342, which amended 2008 PA 295 in December of 2016.[54] Across all of the cases modeled, the modeling tool never selected additional renewables beyond the minimum statutory target of 15%.

[54] MCL 460.1028(1) now relevantly states: "An electric provider shall achieve a renewable energy credit portfolio as follows: . . . (c) In 2021, a renewable energy credit portfolio of at least 15% . . . ."

However, the Company did analyze a "high renewables" sensitivity to reflect a possible future where significant levels of additional renewables were built based on new requirements or other policy decisions rather than on pure economics.[55] The Company has also analyzed a sensitivity associated with the 2017 Reference scenario that would be feasible and consistent with the Company's aspirational carbon reduction goals. Over time and subsequent IRP proceedings, and as technologies evolve, the Company expects that refinements will be made to optimize a resource plan and levels of renewables investment that meets the Company's carbon reduction goals (6T 1611-12; 8T 2472).

The original Reference scenario included an assumption that EE levels would remain similar to programs in recent years at 1.15% annual energy savings. Various sensitivities were tested, including higher and lower levels of annual energy savings. The 1.50% level of energy savings is the sensitivity with the greatest demand reduction while being administratively achievable within a budget that is consistent with previous levels and it achieves the highest benefit to cost ratio (6T 1612). In addition, the PROMOD and internal revenue requirement model were another component of customer affordability consideration. As described by Mr. Chreston, the 1.5% scenario also had the lowest net present value revenue requirement (7T 2054). Therefore, in the 2017 Reference scenario, energy efficiency was assumed to deliver 1.5% in annual savings, which is well beyond the 1.00% legislated mandate for energy savings (6T 1612).

With regard to long-term EE modeling, Mr. Bilyeu further explained that the Company developed a block approach for modeling, which aggregated EE programs into discrete "blocks" of EE categories that reflect the characteristics of existing programs and serve as proxies of yet-to-be-defined future programs (7T 2011-12; Exhibit A-33). The Company worked with GDS Associates, Inc. to complete an EE potential study to act as a roadmap for identifying the amount of achievable

[55] In response to Mr. Evans' criticism about the Company's DR modeling, the Company also removed a DR constraint and reran the optimization. This did not result in a change in the resource plan (6T 1808).

energy savings potential in its service territory (7T 2012-14; Exhibit A-32). Savings characteristics were developed for each block based on the achievable energy savings potential and pricing tiers were identified using historical EE cost data to model future cost increases. The useful life estimates for each block were developed based on the weighted average of DTE Electric's 2018-2019 EE plan and measure lifespan assumptions used by industry standards. The estimated average useful life included in the long-term modeling was 15 years (7T 2014-15).

Mr. Bilyeu further explained that DTE Electric evaluated four sensitivities as part of the IRP process, which are: less than 1.0%; 1.0%; 1.5% and 2.0%. Updating the level of energy savings from 1.15% (in the Reference Scenario) to 1.5% (in the 2017 Reference Scenario) brings the Company's energy savings into alignment with 2016 PA 342 and exceeds the legislative requirement by 50%. The Company selected the 1.5% energy savings sensitivity for its long-term EE plan because it is the sensitivity with the highest Utility Cost Test ("UCT") score of 8.13 and includes the greatest demand reduction while being administratively achievable within a budget that is consistent with previous levels (7T 2010, 2015-16, 2220-21. See also 6T 1752). Mr. Adkins concurred with the Company's 1.5% recommendation (7T 1987). Furthermore, AG witness DiDomenico states "the 1.5% scenario modeled in the 2017 Reference Scenario reasonably reflects an achievable amount of energy efficiency at a level that: (1) meets the new legislative energy efficiency targets; and (2) attempts to maximize the energy efficiency potential identified in the Energy Efficiency Potential Study. Therefore, it is my opinion that the 1.5% scenario is reasonable for the load forecast assumed in this proceeding" (6T 1551).

The IRP modeling considered DR in two ways. First, a minimum level of demand response was assumed as a hard input in all cases, which is consistent with the amount of existing demand response programs and planned expansion of the Company's interruptible air conditioning ("IAC") program that the Company has forecast in resource adequacy filings, and consistent with the amounts approved in the Company's last general rate case, Case No. U-18014.[56] Secondly, demand response options were created within the modeling tools, which were consistent with a recent demand response potential study, totaling over one hundred megawatts of additional demand response beyond the already-planned levels. The Company considers additional demand response as an economical option to flexibly address short-term energy and capacity needs, especially in between larger additions of baseload generation (6T 1612).

The Company's current DSM plan is in-line with achievable potential (7T 2101). Mr. Kirchner also described the Company's efforts in developing future DSM programs (7T 2098-99). The Company modeled the Programmable Communicating Thermostat ("PCT") program, the Bring Your Own Thermostat program, and the Behavior Modification Report with Peak Reduction Demand Response program as potential resource options in the IRP process. The DTE Electric 2017 IRP did not select additional DR resources from these programs, but the Company believes that it is prudent to continue developing them due to the time necessary for development and the flexibility that they ultimately may provide in responding to future scenarios (7T 2100-2101). The Commission has similarly indicated approval for continuing exploration of DR programs with a cautious approach towards further implementation and funding.[57]

It has been suggested that the Company's power need might be better addressed through renewables, EE, and DR programs. The suggestions are inaccurate and overstated because the Company did take these concerns into consideration in arriving at the Proposed Project, which also

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[56] The Company presently has residential, commercial and industrial tariffs that collectively result in 572 MW of DSM (7T 2096-97). The Company expects to increase this to 697 MW by 2021 by adding 125 MW through its Interruptible Air Conditioning ("IAC") program (7T 2100-2101; Exhibit A-31).

[57] See, for example, January 31, 2017 Order in Case No. U-18014, p 25 ("If DTE Electric demonstrates that its DR programs are successful in the initial phases, additional DR expenditures will be recoverable in a subsequent rate case").

leaves room for these other resources to fill the need created by retiring the coal plants (6T 1609). The Company's Proposed Project also leaves room for energy efficiency, demand response, distributed generation such as combined heat and power ("CHP"),[58] and renewables beyond what was assumed in the 2017 Reference scenario while not overbuilding supply-side resources (6T 1613).[59]

MEC/NRDC/SC suggest that there is more DR potential, so DTE Electric has not established that its Proposed Project is "the most reasonable and prudent means of meeting the power need relative to other options for meeting power demand" under MCL 460.6s4(d). (MEC/NRDC/CC Initial Brief, pp 45-58). To the contrary, the ability to actually achieve projected DR potential is speculative, and it is unrealistic to think that there would be enough energy savings to obviate the need to replace the retiring coal-fired generating units. For example, MEC/NRDC/SC witness Mr. Jester suggested an unrealistically-high level of DR potential based on a Statewide Potential Study that placed over 1,000,000 Lower Michigan residential customers on Time of Use ("TOU") rates in the next four years, which is unrealistic. The Commission recently observed that it received numerous comments opposing DR programs and mandatory TOU rates, and stated that it is "unaware of any jurisdiction that mandates TOU rates, nor is there any intention to require individual customers to participate in TOU programs in Michigan" (November 7, 2016 Order in Case Nos. U-17936 and U-18013, p 4).

Moreover, the Company has had a Time of Use rate for over 20 years, and has only

[58] The Company's Distributed Generation experience includes the residential solar program, SolarCurrents, and a proposed Distributed Customer generation pilot (7T 2094). Through 2016, the Company had about 1,400 net metering sites with approximately 11.7 MW of installed generation. Over 98% of installed net metering capacity is solar (7T 2103).

[59] AG witness DiDomenico suggested (but the AG's Initial Brief does not pursue) that the 2017 Reference scenario should include the 138 MW of UCAP capacity associated with DTE Electric's planned investments in the Programmable Communicating Thermostat program, Bring Your Own Thermostat program and Behavior Modification Report with Peak Reduction Demand Response program. The record reflects that the referenced programs were modeled in the IRP as a potential resource, but were not selected. The ability to fund and implement these programs is also speculative because they require regulatory approval (7T 2107-2108).

approximately 8,000 customers sign up for that rate. Based on Mr. Jester's proposed 45.6% load share for the Company, the Company would be required to find a way to enroll over 450,000 customers on the TOU rates in four years (7T 2109). Mr. Jester also inappropriately applied the 45.6% load share ratio to the results of the Statewide DR Potential study regardless of the technology, program or existing customer make-up and penetration within the service territory of DTE Electric. For example, Exhibit MEC-46 proposes that DTE Electric has up to 68 MW of potential in Direct Load Control (DLC) Water Heating in 2023. DTE Electric's current penetration of electric water heaters is less than 0.5% of the Company's overall bundled sales forecast for 2017. The majority of the Company's customers have gas water heaters, not electric (7T 2110). Thus, even assuming that customers should be forced onto TOU rates as MEC/NRDC/SC suggest, they still could not save electricity that they are not using in the first place.

DTE Electric further notes that while Staff is critical of the Company for allegedly not doing enough for DR here (Staff Initial Brief, pp 31-32), Staff opposed the Company's request for additional DR funding in the Company's pending general rate case, Case No. U-18255. DTE Electric is attempting to move forward with all appropriate speed, but disallowing funding only makes progress more difficult (the ALJ proposes following Staff's recommendation to disallow funding (U-18255 PFD, p 19)). Attempting to move forward in the face of Staff's opposition (and lack of funding) also weighs against overly-optimistic DR planning.

The Statewide DR potential also assumes that any customer on an existing DR program will remain on that program and does not account for customers shifting from one DR program to another (7T 2110-11). Mr. Jester also neglects to consider that simple calculations of customer load over peak hours do not replicate actual customer behavior. TOU rates just provide the ability for customers to help lower overall peak load, but customers could still choose (or neglect) to pay more for power (7T 2111-12). DTE Electric supports the existing TOU tariffs and programs, and will continue to develop new programs, products and services as they become available, are cost effective and are of interest to customers (7T 2112).

While recognizing that the Company has satisfied applicable requirements for this case, Staff suggests that the Company could do more to fulfill DR potential, in accordance with Staff's other comments about the Company's MCL 460.6t IRP filing next year (Staff Initial Brief, pp 30-33).[60] Staff states, for example, that: "Though the IRP modeling criteria were not available to the Company at the time the application was filed, Staff believes that the Company has not fully modeled that demand response (DR), in conjunction with energy waste reduction (EWR) and renewable energy (RE), discussed further below, may provide a cost-effective solution to reduce the size or number of gas plants needed to fill the capacity shortfall and could delay a construction date for this proposed project and future fossil projects" (Staff Initial Brief, p 31). However, Staff's stated suggestion ranges far beyond this case, which concerns the Company's proposal to build a 1,100 MW combined cycle gas plant to largely replace retiring coal-fired capacity. The Company seeks CONs for its one Proposed Project (instead of a "number of gas plants" or "future fossil projects" as Staff suggests), and DR, market purchases and other resources are already recognized in the appropriate context (6T 1603, 1606, 1609, 1756; 7T 2309-10).

DTE Electric's IRP indicates that the Company will require 472 MW of additional capacity to meet its projected PRMR beginning in 2022 (the PRMR forecast of 10,744 MW minus Total Planning Resources of 10,272 MW). This shortfall grows to 1,266 MW in 2023 after the announced coal plant retirements are complete (6T 1718-21; Exhibit A-4 2nd Revised, page 99). The Proposed

[60] DTE Electric again incorporates the discussion in section IV above regarding how it will proceed appropriately next year.

Project needs to be commercially available by June of 2022 to meet the Company's summer peak load requirement in 2022. MISO's compliance requirements including a generation verification test must be completed by March of 2022. To achieve these dates, construction is planned to begin in the spring of 2019.[61] Much has to be done before construction can begin and there is a relatively short time to complete everything (8T 2605-2606; Exhibit A-42). Therefore, absent an actual and viable alternative (which nobody has even suggested), Staff's suggestion to "delay a construction date for this proposed project" would not be reasonable or prudent. [62]

Staff's suggestion that the Proposed Project's size (presumably meaning electric output) could be reduced is also not realistic in light of how gas plants are built and how they operate.[63] Mr. Banks explained that the Company proposes the most efficiently-designed plant for customers. Partially replacing the proposed plant's 1,100 MW output would reduce the plant's efficiency.[64] The plant's size was selected based on the IRP results. 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. Plant size is selected based on these standard designs to

[61] Mr. Weber provided additional detail regarding the four phases of MISO planning, and the schedule of payments related to transmission upgrades identified in the Definitive Planning Phase ("DPP") of the MISO Large Generator Interconnection Agreement ("LGIA") procedure (7T 2162-63; Exhibit A-34).

[62] ABATE's suggestion that there would be no time problem with requiring the Company to refile its case in conformance with new MCL 460.6t IRP filing requirements is frivolous in light of the record and common sense. The suggestion is also unlawful as discussed in section IV of DTE Electric's Initial Brief and above regarding the Company's compliance with applicable filing requirements in this case.

[63] Staff's suggestion would also require DTE Electric to re-bid the Proposed Project and require the Company to re-file this case, which would result in the delay of new plant operations to well beyond 2022.

[64] The combustion turbines are built to a design that maximizes the thermodynamic and electrical efficiencies available. Implementing non-standard plant designs, or a 1x1 advanced class, or an older design F-class arrangement, would negatively impact the overall efficiency of the plant. For each 1% in heat rate degradation, approximately 630,000 mmBTUs additional natural gas will be required annually, resulting in higher customer costs of approximately $3 million annually (assuming $4/mmBTU natural gas pricing). (7T 2316).

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 (7T 2316-17).

It also bears emphasis that the entire discussion about the "availability and costs of other electric resources that could defer, displace, or partially displace the proposed generation facility" concerns an IRP analysis under MCL 460.6s(11)(f). There is no statutory provision (and it would defy common sense) to "defer, displace, or partially displace" the need to replace retiring generation plants. Yet there appear to be underlying themes (particularly by the environmental intervenors) to do exactly that. In other words, despite the undisputed need for capacity (unless the Tier 2 coal plants keep operating as ABATE suggests), some parties suggest that because there are inconsequential numbers to quibble about, and possibilities that nobody is willing to pursue, the Commission should derail the only proposal to replace retiring capacity. That would be an unlawful and absurd result for DTE Electric's customers.

The relevantly-requested CON is "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." MCL 460.6s(3)(b). The whole point of the statutory scheme is to fully address "that power need" as further indicated in the immediately preceding MCL 460.6s(3)(a). Guidance by analogy is also provided by *In re Application of International Transmission Co for Expedited Siting Certificate*, 298 Mich App 338; 827 NW2d 385 (2012) *rev'd in part on other grounds, app den in part*, 493 Mich 947; 828 NW2d 22 (2013), where the Court of Appeals upheld the Commission's issuance of a wind energy transmission line siting certificate, and its determination that the route is feasible and reasonable, to enable the wind potential from Michigan's Thumb Region to be realized.[65] The Commission reasoned in part: "There is unrebutted testimony on the record to the effect that the current transmission system is at or near capacity at this time and failure to add additional capacity will frustrate the Legislature's direction for the Commission to facilitate the development of wind power in this State" (February 25, 2011 Order in Case No. U-16200, p 53).

The Court of Appeals rejected arguments that the Commission's decision might result in the overbuilding of transmission capacity, explaining in part that "the statute does not authorize a transmission line that will realize some, most, or even a reasonably anticipated amount of wind potential. It says the line must be capable of meeting *the* wind potential. Anything less than the maximum estimated capacity arguably fails to meet this standard." 298 Mich App at 364 (Emphasis in original). Similarly here, the need for power due to the retirement of the Tier 2 coal plants is beyond credible dispute, and suggestions that ignore or otherwise fail to fully and tangibly address "that power need" would "frustrate the Legislature's direction."

MEC/NRDC/SC suggest that DTE Electric's energy efficiency analysis is deficient (MEC/NRDC/SC Initial Brief, pp 32-44). However, Mr. Bilyeu responded to MEC/NRDC/SC witness Neme's criticisms by explaining that the Company attempted to maximize the energy efficiency potential identified in the GDS Energy Efficiency Potential Study ("Potential Study").[66] Although the 1.5% and 2.0% scenarios deliver greater energy savings in the early years, all scenarios greater than 1.0% eventually converge when the full energy efficiency potential

[65] The Supreme Court also affirmed the Commission's determinations, but reversed an element of the Court of Appeals' opinion that is not relevant here.

[66] See also March 28, 2017 Order in Case No. U-18262 *et al*, p 12 ("by 2019, EWRPs should substantially conform to the results of the potential study").

determined by the Potential Study is achieved (7T 2027).[67] A 50% incentive level is appropriate and commonly used in potential studies (7T 2028-29). The Company has achieved high levels of energy savings at low costs compared to peer organizations (7T 2031). There is no merit in Mr. Neme's assertion that potential studies underestimate achievable savings (7T 2025, 2032-36).

Mr. Neme simply assumed that 2.0% energy efficiency can be achieved without any supporting data, which is unrealistic based on actual results and available technology (for example, high levels of CFL and LED residential lighting savings will no longer be applicable). The ACEEE 2017 *Utility* Scorecard identified only four utilities in the nation that achieved savings of 1.50% or greater. The average percent savings of the 52 utilities included in the ACEEE 2017 *Utility* Scorecard is 0.9%. Only two utilities, both in Massachusetts (Massachusetts Electric, MA and NSTAR Electric, MA) achieved savings of 2.0% or greater, both at a cost greater than 10% of revenue (7T 2038-40).

Mr. Neme suggested that there is no reason to think other states could not achieve results similar to that of Massachusetts. To the contrary, for example, the average retail price for electricity in Massachusetts was 16.9 cents per kWh in 2015 while the average retail price for electricity in Michigan was 10.76 cents per kWh, which is nearly 40% less than Massachusetts. Various other geographic, demographic, economic, and regulatory differences must also be considered rather than blindly assuming that performance would be replicated elsewhere (7T 2037).

Mr. Neme also asserts that DTE's 1.5% and 2.0% sensitivities fail to achieve such levels of savings after 2024 and 2022, respectively (MEC/NRDC/SC Initial Brief, p 35). However, Mr.

[67] Mr. Lucas inaccurately indicated that the Company assumes no energy efficiency will be implemented after 2030. However, simply because the analysis timeframe was through 2030 does not mean EWR programs will stop (7T 2052). Mr. Lucas also inaccurately stated that the Company applied "ceilings" on energy efficiency savings potential. Instead, the referenced "ceilings" are the annual energy savings targets for each of the scenarios (7T 2052).

Bilyeu explained that the 1.5% and 2.0% savings scenarios accurately reflect how long the Company may achieve their respective targeted annual energy savings based on the EE Potential Study so they are realistic and achievable (7T 2027). Mr. Neme's assertion to simply assume these levels of savings may be sustained without any supporting data is inappropriate and fails to adequately evaluate efficiency as a resource. Since this Commission requires an expert's supporting data to be in evidence pursuant to MRE 703,[68] Mr. Neme's failure to provide such supporting data renders his assertion fatally deficient and merits zero evidentiary weight as a matter of law.[69]

Mr. Neme's Alternative 2.0% Energy Efficiency Scenario also overstates energy savings and understates costs. First, he improperly adjusted the Company's load forecast (resulting in an overestimate of achievable energy savings and an underestimate of costs), as discussed in DTE Electric's Initial Brief and above. Second, he reduced energy efficiency costs by an amount of efficiency he believed to be embedded in the Company's load forecast, thereby neglecting that the Company would still incur the entire costs of operating a program targeting 2.0%. The combined effect of these incorrect cost assumptions leads to an approximate NPV under estimation of $117 million through 2030 (or $72 million as compared to the 1.5% scenario). He also incorrectly underestimated efficiency savings life by not considering the Company's future programming impacts, which call for increased reliance on long-lasting measures (7T 2025-26, 2042-45). Mr. Chreston further explained how and why the Company properly modeled energy efficiency in Strategist (6T 1805-1808).

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[68] MRE 703 states in pertinent part that: "The facts or data in the particular case upon which an expert bases an opinion or inference shall be in evidence."

[69] See generally, the Dec. 20, 2011 Opinion and Order in Case No. 16582, pp. 14-17; see also the Dec. 19, 2013 Opinion and Order in Case No. U-17302, p. 3.

Staff proposed that the Company implement the 2% savings scenario for 2019-2020 as a condition to receiving the Certificate of Necessity (5T 252-53). However, Staff does not directly advocate that proposal in its Initial Brief, but it does include an argument indicating that Staff has concerns about the Company's "bare bones EWR program" (Staff Initial Brief, pp 33-39). The Company maintains that the attempted use of this case to impose a higher level of EWR savings is inappropriate since: 1) the Company has demonstrated that the assumptions in the 1.50% scenario are the most reasonable and likely to deliver the projected net energy savings; 2) the Company already has a plan filed for its 2018-2019 EWR programs; and 3) the Company will file another integrated resource plan by March 29, 2019 (7T 2026, 2051). The 1.5% scenario is also the most economical as demonstrated by both the net present value revenue requirement and the Utility Cost Test (7T 2049-50, 2054). Staff's proposal also goes beyond the scope of this case and "Staff acknowledges that EWR will not replace the 1100+ MW electric generating build requested in this filing" (5T 252).

Staff further states that DTE may ramp up its EE programs since "[t]he Company also ramped up from 1.15% to 1.5% for program years 2017, in Case No U-17762" (Staff Initial Brief, p 33). However, Staff's statement is incorrect. In fact, Mr. Bilyeu explained that when the Company amended its 2017 EWR plan due to the passage of Act 342, the savings target only increased from a historical average of 1.35% to 1.40%. In 2017, the savings target was prorated due to the timing of new legislation and therefore targeted 1.4% rather than 1.5%. The Company could target a slightly higher savings level without increasing spend by increasing its reliance on residential lighting measures. However, the ability to ramp up residential lighting will not be available in future years (7T 2050).

Staff suggested that many states meet and exceed annual savings of 1.5% (5T 244). However, the statement appears to refer to Table 9 of the ACEEE 2017 *State* Energy Efficiency Scorecard, which indicates only six states did so in 2016. Three of the states (Rhode Island, Massachusetts, and Vermont) achieved greater than 2% savings while the remaining three states (Connecticut, California, and Washington) achieved between 1.53% and 1.54% savings. Massachusetts' high energy prices, as discussed in DTE Electric's Initial Brief and above, and geographic differences plainly exist between Michigan and the six states located in the northeast and west coast. A few other states may have set aggressive targets, but they have not yet achieved them (7T 2045-46).

Mr. Bilyeu further explained that Staff relied on the Michigan Lower Peninsula Electric Energy Efficiency Potential study, which was completed by GDS in August of 2017, and therefore not available when DTE Electric filed its CON application. DTE Electric incorporates the comments in section IV of its Initial Brief and above, and further notes that the base case average annual savings through 2030 is 1.25%, which is consistent with the results of the Company's Potential Study (7T 2047). However, it appears that Staff improperly relied on incremental annual energy savings, which should never be relied upon for integrated resource planning because it will grossly overstate the impact of energy efficiency on a utility's load forecast. Instead, Staff should have considered cumulative annual energy savings (7T 2047-48).

Staff further asserts that "[a]lthough the [Michigan Lower Peninsula Electric Energy Efficiency Potential study] was not completed at the time of filing, it was an ongoing project during the time period before filing, and was completed and issued only one month after the filing" (Staff Initial Brief, p 33). However, a comprehensive IRP process takes considerable time to develop. In fact, the modeling for EE was done from June 2016 through February 2017. Therefore, Staff's

Statement that "it would not have been difficult for the Company to adjust its EWR targets" is inaccurate (Staff Initial Brief, p 34).

"Staff agrees that increasing the incentive levels to 100% would increase the budget for EWR," but suggests that this might still be worthwhile (Staff Initial Brief, p 37). To the contrary, the 100% incentive scenario is not economically justified because it would only slightly increase savings through 2036 (from 20.4% to 23.8%), but annual program budgets would average about 50% higher than the base case potential study analysis (7T 2048-49). Mr. Bilyeu further explained:

> "Well, to clarify, to assume a 100-percent incentive scenario would mean that every measure that the Company offers would pay out 100 percent of the incentive throughout the entire timeframe of the analysis, which you know, my experience is I've never seen that happen, I'm not aware of any utility that does offer that, so I would classify that as, you know, unrealistic or inappropriate" (7T 2074-75).

Furthermore, Staff asserts that "witness Gould does not state the incentive level should be 50% or 100%, but that there may be an area in-between that would be the best option for the Company when developing the amount of EWR to implement" (Staff Initial Brief, p 33). However, what Staff omits is the fact that the Michigan Lower Peninsula Electric Energy Efficiency Potential Study only provides potential values at the 50% and 100% incentive level. There is no data available for an area "in-between" as Staff suggest (Staff Initial Brief, p 33). Mr. Bilyeu further explained that:

> "[DTE's] average [incentive] is 36 percent that we offer to customers. What we find is, and what best practices find is 30 percent is enough to move the market. Again, we averaged 36 percent in the '18-19 portfolio, 50 percent was used in the potential study, which is more than what we currently offer" (7T 2075).

Staff also makes erroneous assumptions regarding the burdens of ramping programs up and down (7T 2026, 2050-51). However, Mr. Bilyeu further explained:

> "Although the 2.00% sensitivity provides energy savings at a greater rate through 2022, it does so without regard to maintaining a consistent spend and energy savings. Since the Company may only maintain 2.00% energy savings through 2022, customer rates would be inconsistent resulting in unnecessary fluctuations. In addition, the 2.00% sensitivity creates the most inconsistency at an administrative level. It would

> be administratively burdensome to ramp programs up for a short period of time and then ramp back down. This fluctuation may result in poor trade ally, vendor, and customer satisfaction" (7T 2020. See also 7T 2016-17, 2019).

MEC/NRDC/SC suggest that DTE Electric should have assumed the renewal of its existing PURPA contracts with Qualifying Facilities ("QFs"). (MEC/NRDC/SC Initial Brief, pp 28-30). To the contrary, it would be unreasonable to plan on capacity from potentially renewing PURPA contracts because one can only speculate what might occur with PURPA facilities and the law affecting them between now and when the contracts expire, which is between June 2024 and 2039. There are also technical concerns, particularly because approximately 95% of DTE Electric's 104 MW of PURPA-contracted capacity is comprised of landfill gas projects or municipal solid waste generation. To renew capacity contracts with such projects, it is necessary for the projects to have sufficient landfill gas or municipal solid waste to fuel their projects for the term of a renewed contract. The Company does not have this critical information and cannot reasonably be expected to speculate about the availability, interest, and capabilities of these projects to renew their contracts years from now when the contracts are set to expire. MEC/NRDC/SC also inappropriately assume perpetual agreements with QFs, which is contrary to the bargained-for term in the Company's PURPA contracts (6T 1819-20; 8T 2347-48, 2391-92).

MEC/NRDC/SC suggest that DTE Electric is relying on "speculation" (MEC/NRDC/SC Initial Brief, p 29), but they disregard Mr. Bloch's filed testimony (outlined above) as well as his further explanation on cross examination:

> "As I stated in my testimony, the majority of these contracts are tied to landfill gas projects or municipal waste projects . . . my experience with the landfill gas projects, many of these projects have been under contract for 25 years, and when those contracts were initiated, they were based on the sustainability of landfill gas coming out of those landfills, and when those landfills close, this is a limited source. So that's one of the technical concerns I was trying to point out. So to me, it's not simply do they want to re-up, it's their ability to re-up. I could give you other answers as well.

> "I mean landfill gas projects are also looking at the time their contracts expire, what other options do they have. Some landfill gas projects, if they have sufficient gas, may choose to sell their gas to industrial process; that's not uncommon, and we're aware of that happening" (8T 2391-92).

Staff agrees, stating that: "Staff partially agrees with Company witness Bloch's concern about the fuel supply longevity, as it relates to existing contracts. Staff specifically agrees with Bloch's testimony regarding landfill gas and municipal solid waste projects. These are in large part 25-year PURPA contracts. When landfills close, the fuel supply is limited and continues to taper off. (8 TR 2391)." (Staff Initial Brief, p 28).

Staff goes on to say, without explanation, that "Staff is not, however, persuaded that the Company is justified in assuming that, for IRP purposes, none of the contracts will be renewed" (Staff Initial Brief, p 28). The statement appears to be related to Staff's concerns about next year's MCL 460.6t IRP filing, to which the Company incorporates its prior comments about proceeding appropriately at that time in accordance with whatever law and guidance is applicable. The Company also acknowledges that Mr. Bloch indicated that he would expect that "a little bit of hydro" would likely renew, but this matter is inconsequential to the result here because "it's not very large in the overall picture . . . 5 megawatts" (8T 2392).

ELPC asserts that DTE Electric failed to account for expanding development under PURPA because "Michigan is on the cusp of an increase in solar development under PURPA" (ELPC Initial Brief, p 21) based on avoided cost rates under consideration in pending PURPA Case Nos. U-18090 (Consumers Energy) and U-18091 (DTE Electric). To the contrary, it would be speculative to rely on these pending cases to spur development for capacity planning purposes.[70] The cases also threaten a market aberration that would bestow windfall profits on PURPA developers to the corresponding detriment of Michigan utilities and customers. The Commission recently recognized that it caused a "significant uptick in solar QFs seeking to enter into PPAs" and continues to consider matters by reopening Case No. U-18090 once again, staying implementation during the reopened proceeding, and seeking comments in yet another proceeding (February 22, 2018 Order in Case No. U-18090, pp 6, 11-13).

Staff observes that DTE Electric's interconnection queue indicates considerable interest in PURPA contracts by developers of utility-scale solar systems (Staff Initial Brief, pp 28-29. See also ELPC Initial brief, p 18; MEC/NRDC/SC Initial Brief, pp 30-32). While potential developers may be waiting in the wings for an opportunity at windfall profits, this posturing is irrelevant for capacity planning purposes. The current interconnection queue consists of interconnection applications submitted in advance of any clear commitment to build by the developer or a purchase commitment from DTE Electric. Without these commitments, and the important terms and conditions that would accompany such commitments, these applications are purely speculative in nature and should have no bearing on DTE Electric's current capacity planning (8T 2351).[71]

It also bears emphasis that the recent developer interest is being driven by the prospect of avoided cost rates that are based on the Staff's hybrid proxy model. However, this does not

[70] An agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by evidence that a reasonable person would consider adequate).

[71] In Case No. U-18090, the Commission has noted that even *"ELPC argues that…there are few barriers to joining the interconnection queue, even if many of the projects currently in the queue will not ultimately be viable."* (February 22, 2018 Order in Case No. U-18090, p. 8)

properly represent the costs of a NGCC, which is the generating resource the Company is proposing in this case. In fact, it is not surprising that the possibility of lavish profits is motivating interest in solar development. This market stimulation highlights that the Staff hybrid proxy method results in avoided cost rates that are far too high, yielding excessive potential returns to third-party developers, and are not representative of DTE Electric's true avoided costs. If approved by the Commission, then the Staff hybrid proxy method will result in overpaying solar developers at the expense of DTE Electric customers (6T 1820-21; 8T 2349-50).

In addition to overpricing capacity, there is also a problem with having to pay for capacity before there is a need for that capacity (8T 2357, 2380). Staff appears to have been initially persuaded by the flawed views of those who are trying to distort PURPA for their own gain (Staff Initial Brief, p 29). Trade associations representing developers further argue against utilities being able to retire and replace plants (as has always been the case, and what is essentially at issue here). Instead, any future need would be a need to be filled by QFs now, albeit at Staff's artificially-high hybrid proxy method prices. There would then not be a need, so no plant could be built, even though building the plant would be less expensive (and at the appropriate future time) compared to the PURPA contracts. If allowed to happen (which it never should), then once utility plants are retired, Michigan customers will be saddled with long-term third-party contracts for expensive intermittent electricity. Fortunately, the Commission has apparently recognized a need for more thorough and thoughtful consideration (February 22, 2018 Order in Case No. U-18090; February 22, 2018 Order and Notice for Opportunity to Comment in Case No. U-20095).

Staff further suggests that Company witness Mr. Bloch agreed that new PURPA contracts could help to hedge against gas price volatility (Staff Initial Brief, p 29). More accurately, Mr. Bloch testified that a fixed-price contract could (obviously) eliminate price volatility; however, if the contract price is set too high, then customers would be overpaying to "hedge" against upside price risk (8T 2361).

ELPC also criticizes DTE Electric for allegedly giving "only cursory consideration of battery storage resources and applications that could address customer needs, improve grid function, and reduce system costs, despite the fact that battery storage and other advanced energy storage resources are beginning to transform the U.S. energy landscape" (ELPC Initial Brief, p 24). To the contrary, DTE Electric did appropriately consider such possibilities, they just remain expensive and impractical (See for example, Exhibit A-4 2nd Revised, pp 125-128, which relevantly concludes that the Company "will continue to evaluate and track battery storage as an option for investment in its generation fleet. As costs decline, performance improves, and the market framework for batteries evolves, the Company's perspective on its economics and range of applications may change"). As Ms. Dimitry succinctly testified: "Energy storage currently isn't economic" (6T 1678).

The result is unchanged by ELPC's suggestion that "respected industry analysts anticipate significant declines in the cost of battery storage resources over the next five years" (ELPC Initial Brief, p 28). However, this is not Shark Tank. While there may be potential benefits of battery storage, the Company's business is to supply reliable and cost-effective electricity, not to finance potential technologies before they become economic for Michigan customers. Moreover, the apparent point of ELPC *et al* (including the Solar Energy Industries Association) advocating battery storage is to address the inherent intermittency of solar generation, but combining Michigan's relatively weak solar resource with expensive battery storage would only make the resulting power doubly expensive.

ELPC suggests that renewables are reliable as compared to a CCGT plant (ELPC Initial Brief, pp 15-18). This suggestion is incorrect because reliability means that electricity is available to customers when they need it. However, an intermittent resource such as a wind and solar plant provides generation based on the vagaries of the weather and/or time of day instead of being based on the customers' demands. In stark contrast, a CCGT plant as proposed in this proceeding by the Company will specifically operate based on customers' demands for electrical energy. UCAP data further reflects that the Company's existing wind received only approximately 12-16% of their installed capacity as MISO UCAP credit and existing solar resources received approximately 30% credit in the most recent MISO planning year (Exhibit A-17). Electrical power grid stability also requires that generation and load be matched on a constant, continuing and nearly instantaneous basis. As compared to a CCGT, wind and solar resources have very limited capabilities to meet customers' varying needs for power (7T 2317-19).

ELPC witness Mr. Lucas also inaccurately suggested that the Proposed Project would not be flexible. To the contrary, the Proposed Project will be flexible because it is being designed so that it can operate in a cycling, a load-following, or a baseload condition. The Proposed Project will also be able to startup, shutdown, increase, or decrease its electrical output quickly, thereby supporting the rapid load changes that occur at certain times of the day. The Proposed Project plant will also be able to adjust its electrical output by 100MW/minute, enough to quickly power 20,000 households per minute (assuming a household uses 5kW), over a range of 800MW. Thus, as customers' electrical demand goes up and down, the plant will operate in a flexible and reliable manner to continuously meet that demand (6T 1640-41; 7T 2320). Moreover, even Mr. Lucas' testimony supports the Company's position:

> "…DTE must maintain sufficient capacity to keep its system reliable. Flexibility – both on the generation side and the demand side – is key. As more variable resources such as solar and wind are introduced, matching supply with demand will require more attention. The ability for generators to respond quickly to changes in solar and wind generation, and to ramp their output up or down, is critical." (5T 754).

ELPC suggest that their witness Mr. Beach presented a "concrete example of a flexible, cost effective, flexible [sic], and clean solution the Company could have considered" (ELPC Initial Brief, p 18). To the contrary, neither Mr. Beach, nor anybody else, presented a "concrete example" of any alternative to the Proposed Project, as discussed above. Mr. Beach's proposal also fails to survive even cursory consideration. He essentially proposed that the Commission find that DTE Electric's proposed NGCC plant is too expensive and too risky due to volatility in the price for natural gas fuel, and that the Company should instead procure renewable resources through the Staff's PURPA avoided cost pricing methodology. However, Staff's PURPA avoided cost methodology is based on a hybrid proxy NGCC/NGCT plant and produces substantially higher PURPA avoided cost rates than DTE's proposed NGCC, as discussed above and further demonstrated by DTE Electric in Case No. U-18091. Staff's PURPA avoided cost methodology also sets energy prices based on long-term natural gas forecasting instead of actual costs as proposed by DTE Electric. Thus, Mr. Beach's alternative proposal actually has *more* gas-forecast risk and would impose *higher* costs on customers than the Company's proposal. Witness Beach's suggestions (reject DTE Electric's proposal allegedly based on risk and cost, but instead adopt a riskier, more expensive alternative that is still based on gas price forecasting) are also internally inconsistent and lack credibility (8T 2350-51).

Mr. Beach's proposal for a renewable energy portfolio that allegedly would be "less risky" than the Proposed Project also assumed 1,100 MW of wind installed capacity additions in seven years from 2019-2025 and an additional 1,110 MW of solar in nine years from 2018-2026. Ms. Schroeder explained that these assumptions are unrealistic because they do not reflect the opposition that utilities and developers are currently seeing from local communities that do not want such projects. Recent decisions in some of Michigan's Thumb communities reflect increased anti-wind activity. Similar activity is surfacing elsewhere in Michigan where potential wind energy projects are in various stages of development. Similarly, some communities have issued moratoriums on solar developments after developers aggressively solicited land for solar developments to ensure compatibility with the agriculture industry in rural areas (8T 2484). This public opposition not only affects the ability to build renewable energy projects, but also the capacity factors and corresponding energy cost of anything that likely can be built going forward, as Staff recognized, stating that: "Staff believes it is also reasonable for the Company to utilize lower capacity factors for wind as current moratorium and public backlash in the Thumb region may exclude future wind development in the region. . . This will cause an increase in the LCOE of wind" (Staff Initial Brief, pp 25-26).

Therefore, from a development perspective, the proposed gas plant is much less risky than numerous wind and solar projects that might never be developed. In addition to the risks of local opposition, Mr. Beach's model (Work Paper "Resource Plan for DTE") is also unachievable because it assumes utility scale solar and wind in 2018 and 2019, respectively, with a corresponding MISO credit and a full year of energy production in that year. These assumptions defy reality and should be rejected (8T 2484-85). More specifically, to achieve full MISO credit in a given year, projects would have to be registered and online prior to the start of the MISO planning year. To achieve a full year of energy production, projects would have to be completed and online by January 1 of that year (8T 2484). Furthermore, while there are some wind and solar projects in the MISO queue, official kick-off of the next Definitive Planning Phase ("DPP") study has been delayed until March 2018. The DPP study/Generation Interconnection Agreement ("GIA") process takes an estimated 500 days to complete. Therefore, under a best-case scenario, projects in the current DPP cycle would not have GIA's until July/August of 2019 (8T 2485).

Mr. Beach also claimed that "avoided [line] losses and transmission costs reduce the cost of commercial DG solar by about $20/MWh." (5T 944). However, Mr. Beach's claim is irrelevant because altering those expenses does not reduce the cost of Distributed Generation ("DG") solar. Furthermore, a recent study for the Advanced Energy Economy Institute (AEE) by Demand Side Analytics, LLC and Optimal Energy, Inc. provided an assessment of the economic potential for peak demand reduction in Michigan. Page 12 of the report states that: "In an area with declining loads there is effectively no T&D benefit associated with peak demand reductions." With DTE Electric's flat load forecast, this suggests that avoided T&D may be of little value in the Company's service territory at this time (7T 2035, 2080).

D. Potential transmission upgrades are not a reasonable or prudent possibility to satisfy DTE Electric's need for additional capacity.

DTE Electric's Initial Brief, pp 59-62, explained that, based on an analysis of transmission import capability performed by HDR, the Company concluded that it is unlikely that the import capability of the transmission system into the Lower Peninsula of Michigan could be expanded in time to offer a realistic alternative approach to the Proposed Project. Supply adequacy forecasts for MISO regarding the availability of excess capacity in surrounding regions have been fluid with last year's report predicting a shortfall as early as the summer of 2018 and this year's report predicting a small cushion of excess capacity. These capacity forecasts are fluid because load forecasts may increase or decrease and existing plants may experience problems or retire earlier than expected. Even 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 (6T 1613, 1727; 7T 2167; Exhibit A-4 2nd Revised, IRP report, section 8.1).

Staff agrees with the Company's conclusion, stating:

> "Although there may exist additional transmission and import possibilities that further enable outside resources to serve Zone 7 to a greater degree, Staff understands that the Company cannot rely on the possibility that a resource may be available at a future date if either MISO alters its construct or IESO [Ontario's Independent Electric System Operator] chooses to become a qualified resource. Additionally, Staff notes that no transmission solutions were supported by any transmission owner in this case. For these reasons Staff believes that the Company has appropriately analyzed transmission alternatives in its IRP" (Staff Initial Brief, p 44).

However, in contrast to the Company and Staff's reality-based conclusions, there is an old saying about throwing spaghetti on the wall to see if anything sticks, which is well illustrated by MEC/NRDC/SC's Initial Brief, pp 58-76. In response to MEC/NRDC/SC witness Osborn's various criticisms, Mr. Weber explained that DTE Electric's analysis satisfied applicable CON filing requirements and was based on the best information available at the time (7T 2170-72). Mr. Osborn's vague suggestions that other options may be available to address transmission constraints also failed to present anything viable. As Mr. Weber explained:

> "Any new transmission to relieve Michigan congestion or to increase import capability would require a lengthy study conducted by MISO through their MTEP and congestion study processes, and potentially the MISO-PJM Interregional Process. Additionally, it is important to understand that DTE Electric is not a transmission owner and does not possess the unilateral authority to compel MISO to approve transmission modifications.
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> * * *
>
> "None of the high-level transmission modification ideas to address firm transmission import constraints, presented in Witness Osborn's testimony, have materialized into project proposals in the MISO transmission planning process. As already stated, DTE Electric does not possess the authority to unilaterally compel MISO to approve such projects, and therefore cannot risk its statutory obligation to serve on the uncertain outcome of the MISO stakeholder process and a decision from the MISO Board of Directors. In addition, the project study process to address firm transmission import constraints can be lengthy and uncertain, and the overall timeframe from study to completion, typically several years as witnessed on similar projects, would likely preclude them from consideration as a viable alternative to the proposed project. It is also important to note that any transmission alternatives would only work when a firm generation resource is available to import (7T 2172-73).

Mr. Osborn suggested that the Company did not seriously consider capacity imports into LRZ 7 from other MISO LRZs or adjacent Regional Transmission Organizations ("RTOs"); however, the Company has a sound basis for not further evaluating capacity imports as replacement for the planned generator retirements. Ms. Wojtowicz explained that simply having firm transmission service and a purchase commitment for an existing capacity resource external to MISO does not change the physical transmission system nor the LRR/CIL/LCR/ECIL of a LRZ. Each LRZ is still required to meet its LCR to achieve acceptable reliability standards (7T 2247).[72] If the Company were to rely on capacity from outside of MISO LRZ 7 (from another MISO LRZ or an adjacent RTO) to replace its retiring coal units, then reliability in LRZ 7 would likely not meet acceptable standards because there would likely not be sufficient local capacity resources to meet the LCR (7T 2248).

Based on recent MPSC Staff projections in Case No. U-18444, LRZ 7 could be as short as 1,407 MW (Exhibit A-55) to meeting the LCR after the retirement of DTE Electric's River Rouge Unit 3, St. Clair Units 1, 2, 3, 6, & 7, and Trenton Channel Unit 9.[73] This projected shortage may

[72] AG witness DiDomenico's suggestion that PRA results indicate transmission capability reflect a lack of understanding regarding how MISO implements its resource adequacy rules. The resources that clear in the MISO PRA and are shown as imports/exports from LRZs are simply the result of an economic solution of all offers in the PRA to meet the PRMR of all LRZs. There is no connection between the PRA results and what LSEs may actually be using on a planning horizon basis to meet their resource adequacy requirements. For example, the Commission concluded in Case No. U-17992 (Exhibit A-59) that there was over 700 MW of external capacity either owned or under contract to serve load within LRZ 7 in Planning Year 2017/18, yet the MISO PRA for the same Planning Year shows imports into LRZ 7 of only 338 MW (Exhibit A-60). (7T 250-51).

[73] Staff suggests: "Although the Company identified a Staff projected shortfall in Case No. U-18444 that could be as much as 1407 MW in Zone 7, while not part of this record, the Commission may take official notice that Staff has updated the shortfall projection in MPSC Case No. U-18444 Rebuttal Exhibit S-25 to 644 MW. (Attachment C)" (Staff Initial Brief, p 43). Staff's official notice suggestion is inappropriate. The Commission recently explained that "because of the unforgiving time limits under MCL 460.6a [which at that time had a 12 month deadline, which was far longer than the 270 day deadline applicable in this case], official notice requests, especially those that may generate controversy regarding the materiality or weight of the evidence proffered, can rarely, if ever, be entertained after the close of the record" (December 11, 2015 Order in Case No. U-17767, p 136, agreeing with ALJ's denial of official notice request). See also, *Freed v Salas*, 286 Mich App 300, 341; 780 NW2d 844 (2009); MRE 201(b).

actually be conservative, as the Staff's approach calculates the LCR by holding the CIL constant at the 2018/19 value of 3,785 MW. When using the projected CIL value of 3,143 MW that MISO published for the 2021/22 Planning Year, the forecasted shortage would be over 2,000 MW (7T 2248).

Suggestions to broadly rely on imported capacity also neglect that the Company is required to demonstrate capacity four years into the future under 2016 PA 341's SRM, as discussed in DTE Electric's Initial Brief. The Company also expects to have a LCR requirement starting in Planning Year 2022/23 pursuant to Case No. U-18444. It would be risky[74] and unreasonable to count on capacity imports greater than the Company's load ratio share ("LRS") of the ECIL. Therefore, it is reasonable and prudent to limit long-term capacity imports to approximately 300 MW to comply with locational requirements and ensure reliability for customers (6T 1818-19; 7T 2249-50).

Mr. Osborn's conjecture that imported electricity from Ontario could replace the Proposed Project is particularly infeasible. Not only would the transmission service and potential modifications necessary to enable such imports require a formal study by MISO (7T 2173), but capacity from Ontario does not meet MISO rules for External Resources, so it cannot be qualified as capacity for use in meeting MISO resource adequacy standards (Exhibits A-61 and A-62). The Independent Electric System Operator ("IESO") in Ontario does not grant the specified firm transmission service, nor does it comply with the recall standards as established by MISO, thus

[74] Even assuming that that there would be available import capacity that the Company could use to meet its resource adequacy requirements, there is the additional risk that the Company could end up paying significantly more than CONE at the same time that reliability in LRZ 7 is diminished. As local resources in LRZ 7 decline, the risk of the zone not meeting its LCR increases. At the point LRZ 7 does not meet the LCR, prices for capacity in the zone will go to CONE in MISO's PRA. If the Company has capacity resources outside of the zone where there may be excess capacity and lower prices, then the Company would receive very little revenue for the external capacity while having to pay CONE for the load serving its customers within LRZ 7. The cost of this price separation would be in addition to the cost of the external capacity purchase. It would not be prudent for the Company to risk jeopardizing reliability for its customers by purchasing large quantities of capacity outside of LRZ 7 at a price that could be the same or even more than the cost of the plant that the Company has proposed in this case (7T 2252).

preventing capacity in its service territory from qualifying in the MISO reliability construct (Exhibit A-63; 7T 2251-52).

Mr. Osborn's suggestion that High Voltage Direct Current ("HVDC") transmission might be a reasonable alternative similarly merits no serious consideration as a viable alternative to the Proposed Project. DTE Electric does not possess the unilateral authority to compel MISO to study and approve HVDC lines. Mr. Osborn's views also appear to be based on his past study of this technology's theoretical potential without regard to the mainstream reality that very little DC transmission is currently in place, being planned, or under active construction in the U.S. Mr. Osborn also ignores the reality that such a line would likely take much longer to plan, permit, and construct than DTE Electric's Proposed Project (7T 2174).

E. When all resources are treated on an equivalent basis, even Intervenors' modeling selects the Proposed Project.

DTE Electric's Initial Brief, pp 62-65, explained that false claims were made, predominantly by ELPC Witness Beach and MEC/NRDC/SC Witness Evans (collectively "Intervenors" for this discussion) that the alternative portfolios created for their modeling exercise would produce high levels of estimated savings (over one billion dollars) as compared to the Proposed Project. Mr. Chreston demonstrated that Intervenors' inconsistent treatment of wind, solar, and natural gas options unfairly distorted the Proposed Project's value. The claimed savings from the implementation of Intervenors' proposed portfolios more than disappear when their modeling is corrected. Instead, the Proposed Project is more economic by approximately $500 million dollars when compared on a fair and equitable basis within the Mr. Evans' Strategist model runs (6T 1773, 1775, 1838-39).

MEC/NRDC/SC attempt to defend their position by arguing that Mr. Chreston did not rerun all of Mr. Evans' modeling (due to the limited time for rebuttal, and lack of need to further demonstrate

Mr. Evans' modeling errors), and that Mr. Evans' modeling might still have some salvageable value despite its errors (MEC/NRDC/SC Initial Brief, pp 92-94). In contrast to this exercise in obfuscation, Mr. Chreston explained that DTE Electric originally compared all projects on an equivalent basis in Strategist. In contrast, MEC/NRDC/SC Witness Allison calculated the "revenue requirement impact of revising DTE's approach such that O&M costs are not treated as capitalized expenses" (5T 475) for wind and solar projects *only*, and provided the values to Mr. Evans for evaluation in certain Strategist runs. By applying this adjustment to wind and solar *only*, the Intervenors created a bias against all other alternatives including gas technologies. Second, these corrections were made on the 2017 most-up-to-date solar and wind cost, yet Mr. Evans chose not to include DTE Electric's Proposed Project as an option to be selected in his analysis, but instead modeled only the original and non-updated generic NGCC options from 2016 data (6T 1777-78).

Mr. Chreston compared the Proposed Project on an equivalent basis using Mr. Evans' modeling as a starting point. Mr. Chreston corrected the treatment of O&M costs and added the proposed project as an option that could be selected.[75] The result is that the Proposed Project is selected in 2023[76] and it results in over $545 million NPVRR in savings as compared to Mr. Evans' Case 0 (6T 1778-80, 1787-88; Exhibit A-77).

Intervenors' criticisms of DTE Electric's modeling are also overstated and inaccurate. For example, MEC/NRDC/SC's Initial Brief, pp 82-83, acknowledges that "the heat rate error appeared in only two modeling runs," but claims that it "undermine[s] the accuracy and integrity of the IRP modeling and analysis." The record further reveals the expanse between reality and

[75] No other changes were made to Mr. Evans' model even though it unrealistically includes significant increases in Energy Efficiency (EE) at little to no cost, and significant amounts of Demand Response (DR) at reduced cost, as discussed above (6T 1778). When DTE Electric re-ran the cases in Strategist (Case 0_B_DTE and Case 9_A_DTE) without changing the renewables assumptions, the proposed plan CCGT was still selected (6T 1812).

[76] The Proposed Project is selected in 2023 because DTE Electric did not attempt to correct Mr. Evans' EE modeling, which incorrectly moves the need for replacement capacity to 2023 (6T 1780).

MEC/NRDC/SC's hyperbole. The majority of DTE Electric's analysis utilizing Strategist was performed on the 36 sensitivities run on the five original scenarios, all of which had Belle River Peakers and new Natural Gas Combined Cycle (NGCC) modeled with the correct forecasted heat rates. There were just two modeling runs/files that had incorrect heat rates. However, DTE Electric recalculated these two runs and the result reaffirmed the same selection of a NGCC resource (Exhibit A-17, p 16). In addition, all the PROMOD detailed production cost modeling used for DTE Electric's actual Revenue Requirement analysis for those key scenarios and sensitivities and the 2017 Reference Case had Belle River Peakers and the new NGCC modeled with the correct forecasted heat rates. Thus, the heat rate errors were immaterial to the outcome of the analysis and do not change the fact that the Proposed Project is the most reasonable and prudent option for this CON proceeding (6T 1775-76, 1781-82. See also 6T 1797-99, 1839).

There is similarly no merit in MEC/NRDC/SC's attempt to leverage the immaterial heat rate errors into a basis to question DTE Electric's Strategist runs. DTE Electric submitted more than 60 Strategist and 30 PROMOD files. The heat rate error was contained in two files that were developed at a different stage and for a different purpose than the other files, thereby undergoing a different quality review than other files. While DTE Electric acknowledges the error in these two files, this does not call into question the quality and validity of the Company's overall IRP process (6T 1782-84; see also 6T1797-98).

Mr. Chreston also discussed and corrected Intervenors' various other flawed assumptions and errors (6T 1785-90). Specifically, ELPC Witness Beach used an Excel model to create a portfolio consisting of increased renewables, increased DR, and 2% Energy Efficiency (the "Beach plan"), which he claimed to offer $339 million of potential savings as compared to the Proposed Project. However, Mr. Chreston identified and discussed seven errors in the Beach Excel model: (1)

heat rate, (2) CCGT capacity factor, (3) wind capacity factor, (4) MISO capacity price, (5) erroneous energy optimization assumptions, (6) solar PPA prices, and (7) improper valuing of the Beach plan net purchases and sales (6T 1791-1795). Mr. Beach also failed to utilize an accurate representation of DTE Electric's Proposed Project. Nevertheless, when a fair representation is made using the Beach Excel model, the Proposed Project is the least cost solution by approximately $500 million (6T 1773-74, 1791).

A concern was suggested about the size of renewable resources that DTE Electric modeled in Strategist. For instance, Mr. Evans' Case 0 utilized ten 100 MW wind increments and ten 50 MW solar increments (See Exhibit A-86 showing the Max capacity of the wind and solar resources). However, DTE Electric maintained these modeling increment sizes in its analysis of Witness Evans' modeling (Case 0_B DTE). The result was that the Proposed Project (Plant F) was still selected (6T 1814).

Staff agrees that there is no cause for concern here, but suggests modeling with the smaller wind and solar blocks next year, stating: "In summary, with respect to renewable costs, Staff is not persuaded that DTE's renewable costs projections are inappropriate . . . The Commission should direct the Company to use smaller blocks of wind and solar in its March 2019 IRP case" (Staff Initial Brief, p 26). DTE Electric again incorporates its comments about proceeding appropriately next year, in accordance with whatever law and guidance is applicable at that time.

Staff proposed a scenario including increased renewables, increased Demand Response, and sustained Energy Efficiency at the 2% level through 2040. Staff remains critical of the Company for not running that scenario for Staff (Staff Initial Brief, p 41. See also p 9). However, to clarify and hopefully finally resolve this matter, DTE Electric emphasizes that it was not trying to be difficult. Indeed, the Company previously attempted to do something similar (finance independent consultant experts) to assist the Staff, despite facing criticism for such efforts. See generally, the June 26, 2007 Opinion and Order in Case No. 15244. The Court of Appeals then effectively removed this sort of practice from the range of prudent possibilities, by indicating that it "creates the appearance of impropriety and unfortunate precedent," and admonishing the Commission in a similar case.[77] Therefore, if DTE Electric had performed Staff's modeling, then the door would have been opened for criticism of the Commission. DTE Electric cannot reasonably be faulted for trying to keep that door shut on the appearance of impropriety that arises when a regulated utility finances or performs the work of its regulators.

In any event, the Company re-ran Mr. Evans' case (CASE 1_A_DTE), which contains increased EE assumptions[78] that can be used as a proxy for Staff's requested scenario. Specifically, "Case 1_A_DTE is a sensitivity to Mr. Evans' Case 1 with Mr. Allison's cost approach applied to DTE Electric's Proposed Project. The Strategist optimization resulted in a plan that is cheaper than Mr. Evans' Case 1 by **$415 million** and includes the Proposed Project in 2023." (6T 1789) (Emphasis in original.)

Thus, after considering all of the input and indicated concerns of other parties' in this case, the Proposed Project remains the best alternative to address the future replacement energy and capacity needs of DTE Electric's customers (6T 1839).

F. DTE Electric reasonably sought market-based alternatives for the Proposed Project, and no third party has offered any alternative to the Proposed Project.

DTE Electric's Initial Brief, pp 66-72, discussed how the Company issued an RFP to assess market-based alternative options from third parties (6T 1610, 1614). The Company requested

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[77] See *In re Application of Consumers Energy Co for Rate Increase*, 291 Mich App 106, 119-20; 804 NW2d 574 (2010).

[78] These EE and DR projections are inaccurate and unachievable as discussed above. See also 6T 1816-17.

competitive bids for PPAs up to seven years in length because over the next few years until the announced coal plant retirements occur, the Company is expected to have either owned or contracted resources within a few hundred megawatts of its full PRMR requirements. Any potential excess or shortfall in a given year is expected to be no more than about two to four percent of the total PRMR capacity requirements. The Company's capacity position relative to its PRMR requirement changes as load forecasts are updated and plant performance fluctuates. Under section 6w of 2016 PA 341, MCL 460.6w, uncertainty exists about whether the Company will be responsible for securing generating capacity to support all or a portion of the customer load served by Alternate Electric Suppliers. Due to this potential, the Company elected to include a request for PPAs with a term up to seven years to gain insight on short-term capacity options. Furthermore, the up-to-seven-year term provides a bridge to the expected timeframe for the next round of coal plant retirements for the Company, which will trigger a new assessment of energy and capacity needs and possible solutions (6T 1615).

Staff indicates that "the 7-year restriction placed on PPAs, as a maximum contract limit, is disconcerting to Staff," and that its "concerns are echoed by" MCV witness Mr. Olling (Staff Initial Brief, p 13). Yet MCV does not seem particularly concerned, since it did not bother to file an initial brief in this case. Staff further recognizes that theoretical criticisms are merely academic because there is no feasible alternative to the Proposed Project in any event:

> "Yet, despite concerns with the bidding process shared by Staff and other parties, no alternative proposals were presented to the Commission in accordance with MCL 460.6s(13). (5 TR 201.) Staff can only assume that since no other alternatives were presented to the Commission, no other feasible alternatives are available at this time" (Staff Initial Brief, p 14).

The Company also believed, and still believes, that the conforming bid requirements are reasonable for third parties that are considering building a project that would supply capacity to support a PPA. Many supply-side resources could reasonably be built before the 2022 planning year start of the proposed term, assuming some initial development work is already underway. The location requirement is consistent with resource adequacy obligations requiring the state to have a minimum amount of local generation in order to ensure grid reliability. The size range allows for significant flexibility for a developer in choosing technologies and designs. Merchant generation has previously been built in Michigan and financing apparently continues to be available for credible developers to build new generation. The Company's seven-year PPA term provides a similar length of price certainty within Zone 7 of the MISO market, and minimizes the risks of misaligned incentives between the Company and a PPA supplier (6T 1615-16).

The marketplace-alternatives PPA did not include long-term contracts because long-term contracts come with risks that can directly impact the Company's ability to reliably serve customers. Some examples of these risks are:

- <u>Performance risk of a counterparty over the contract term:</u> Financial incentives and contractual terms and conditions do not guarantee that a counterparty will perform its obligations under the contract. Monetary remedies also do not alleviate the true impact to physical reliability if a counterparty underperforms or defaults. The Company is ultimately held responsible by MISO for having adequate supply, regardless of whether the counterparty to a PPA performs or does not perform. Further, 2016 PA 341 subjects the Company to the risk of unknown levels of fines, penalties, or customer refunds if the Company's capacity obligations are not met. The Company cannot fully mitigate these risks or transfer these responsibilities through PPA contract terms. Given the Company's demonstrated replacement capacity need of approximately 1,100 MW, the financial exposure to the Company and its customers could be significant in the event of a counterparty default for a PPA of this magnitude.

- Risk at contract termination: The availability and cost to replace capacity at the end of a contract term is highly uncertain, potentially creating extra risks and costs for DTE Electric's customers. If there is an opportunity to cost effectively extend the life of the plant beyond the PPA contract term, then all of the additional value created due to the longer life will accrue to the third party owner, which could re-contract at prices that compete with replacement capacity prices. If that same plant were owned by the Company, then any additional value created by life extension strategies would accrue to the Company's customers as they would receive the benefit of the mostly-depreciated capacity at the cost of ongoing operations rather than paying full replacement costs. The Company has a strong history of and experience in finding cost-effective ways to extend asset lives beyond original forecasts in order to reduce costs to its customers.

- Reduced flexibility: A long-term contract diminishes the Company's ability to adapt operating strategies or make technology or process improvements in the best interest of customers as regulatory constructs and energy markets evolve. For Company-owned assets, benefits from any reduction in operating costs flow back to customers. Under a PPA structure, benefits from reductions in operating costs flow to the PPA owner.

- Misaligned incentives: Under a contract, the economic interests of a counterparty might not align with the optimal operating strategy to support customer reliability and savings. With owned assets, the Company considers its entire fleet and evaluates issues such as outage timing, replacements or repairs, and investments that could extend the life of an asset based on total cost to our customers. A third party might make different decisions because they optimize operations and investments in order to maximize profits.

- Change of ownership during the contract term: Prior to entering any long-term contract, the Company would perform extensive due diligence to validate a potential counterparty as a reputable and stable business partner. In the circumstance where the original counterparty is acquired or sells its interests to another entity, the Company could find itself in a business transaction with a counterparty it would not have selected under its normal due diligence process. Given the nature of the energy market and recent history related to merchant generators, it is not unreasonable to assume a change in counterparty over the life of a contract term.

- Balance sheet impacts: Financial markets view long-term PPAs as liabilities, and may impute debt to the Company's balance sheet, which would negatively impact balance sheet metrics. These impacts could result in increased financing costs which would be borne by DTE Electric customers (6T 1616-18, 1626).

Thus, limiting a PPA term to seven years appropriately mitigates some of the risks associated with long-term PPAs while still allowing sufficient price certainty to developers to finance their proposed projects (6T 1626).

Staff agrees that a long-term contract could present risks to the Company and its customers, but suggests that those risks could be addressed through a well-written contract (Staff Initial Brief, p 14). The discussion is academic because, as indicated above, there is no feasible alternative to the Proposed Project. For completeness, however, the Company disagrees with the suggestion that risk can be contracted away. Although some degree of risk could be mitigated through contractual and financial arrangements, these arrangements can become overly complicated and costly for both counter parties to implement, and ultimately some risk would always remain. For example, a contract could include financial penalties for instances where the counter party fails to perform, but there is still a risk that the counter party may fail to perform. If that happens, then there is a risk that the Contract's financial remedy will not cover the Company's exposure or that the counterparty (which already failed to perform the contract) may be unwilling or unable to pay the financial remedy. Moreover, even if the counter party paid the applicable penalties, those financial remedies may not remedy a true reliability concern (*e.g.*, the asset is unavailable during peak load).[79] Ultimately, the Company has the obligation to reliably serve its customers regardless of contract terms with its suppliers (6T 1626-27).

Although MCV did not file an initial brief, the Company further notes for completeness that Mr. Olling's suggestion that certain ownership risks could be avoided by contracting with a third party like MCV similarly neglects that contract terms do not actually make risks disappear. Contract terms can only attempt to transfer the financial impact of risks. Any developer would certainly factor its own ownership risks into the pricing and terms and conditions it is willing to agree to under a PPA – plus contingencies to increase the chance that sufficient returns will remain if the risks materialize. If the risks do not materialize, then a PPA developer would get to keep the contingencies as added margin from the project. The Proposed Project is superior to a PPA in this respect since contingency is included only for planning purposes for the Proposed Project, but the Company would actually collect only the amount that its spends. In contrast, the Company's customers would have to pay to cover the PPA developer's ownership risks regardless of whether those risks actually materialize with a PPA (6T 1629).

Mr. Olling's suggestion that the RFP process was biased similarly lacks merit. The RFP for natural-gas fueled electric resources was open to all prospective bidders meeting the minimum bid requirements set forth in the RFP. The Company sent notices of the RFP to 22 potential energy suppliers - including MCV - and also issued a press release to broaden awareness of the RFP. Bidders

[79] Ms. Dimitry has extensive experience with PPAs, but has never seen a seen a situation where a PPA provider was willing to agree to non-performance penalties that went beyond the contractual value of the undelivered electricity or, in some cases, replacement value if the Company had to purchase power from other sources to make up for the undelivered electricity. The true impact of non-performance under a PPA could be much larger if reliability issues emerge due to receiving less electricity than expected (6T 1627-28).

had until March 17, 2017 to respond to the Company with a notice of intent to bid, and the actual bids were due on April 13, 2017 (6T 1614). In response to the RFP, two suppliers submitted a total of three bids. One bid was for plant of ~1,100 MW while the other two bids were for seven-year PPAs from simple cycle natural gas plants of ~70 MW and ~225 MW (6T 1618, 1631).

DTE Electric performed a thorough and fair evaluation of the bid for the purchase of an existing combined cycle natural gas plant, comparing it alongside DTE Electric's self-build option using an economic dispatch production cost model to determine the cost effectiveness of these possible resource options. The analysis took into account resource costs such as, but not limited to, asset purchase price (or projected installed costs in the case of the Company's self-build option), expected future fuel costs, non-fuel O&M costs, and ongoing capital expenditures. The resource benefits from capacity and associated energy were also taken into consideration to calculate the net present value of revenue requirements ("NPVRR") for each resource option. In order to account for the difference in the remaining useful life of the bid for the existing plant and the useful life of DTE Electric's Proposed Project, the Company estimated a residual value for the Proposed Project in the year the existing plant is expected to retire.[80] This evaluation process concluded the NPVRR of the Proposed Project was $446 million less than the bid for the existing ~1,100 MW plant (Exhibit A-2). Based on this result, the most reasonable and prudent solution to satisfy the Company's ~1,100 MW replacement capacity need as determined by the IRP analysis is for the Company to build a nominal 1,100 MW natural gas combined cycle generating facility at the Company's Belle River Power Plant site (6T 1619-20, 1631-32).

DTE Electric also evaluated the bids for seven-year PPAs for ~70 MW and ~225 MW from

[80] This residual value was calculated by taking the discounted estimated capacity proceeds and energy margin attributed to the Proposed Project for its remaining years, and reducing this amount by the plant's net book value in the year the existing plant is expected to retire. This calculated residual value in the year the existing plant is expected to retire was included in the calculation of the NPVRR (6T 1619).

simple cycle natural gas plants. Since the ~70 MW PPA did not meet the minimum capacity requirements of a conforming bid for this RFP and the ~225 MW PPA is far smaller than the ~1,100 MW replacement capacity need as determined by the IRP, these bids were not considered as alternatives to the Company's Proposed Project. However, the bids are still being considered as possible short-term solutions to fill potential capacity shortfalls both before and after the Company's Proposed Project is constructed (6T 1619-20).

It bears emphasis that MCV (and other potential energy suppliers) had several opportunities to submit a proposal, but chose not to do so. MCV could have submitted a conforming PPA bid through the Company's RFP process, but did not. MCV also could have submitted a non-confirming PPA bid through the Company's RFP process, as one other party did, but MCV did not. Finally, MCV could have submitted an alternative in this proceeding pursuant to MCL 460.6s(13), but MCV did not. Instead, MCV only chose to inaccurately criticize DTE Electric and suggest that it could build a new generating plant (which it apparently still has not even seriously considered, let alone proposed or pursued) if DTE Electric would enter into a long-term contract to pay for it – plus of course a substantial additional profit for MCV, as discussed above. In the end, MCV did not even bother to file an initial brief in this proceeding.

Ms. Dimitry concluded:

> "The Company's market alternatives RFP was certainly reasonable as it solicited bids for the optimal technology, size, and timing that the Company's IRP identified. The Company's decision to solicit bids for existing plants; plants that would be online by 2022; and for PPAs with term lengths up to seven years reflected an approach that included a wide variety of options while balancing risks for the Company and its customers. Given that PA 341 does not include provisions or guidelines for a market alternatives RFP, yet does provide an opportunity for anyone to submit an alternative proposal directly to the Commission under Section 6s(13), the Company feels that there is no basis for stating that the Company's RFP was unreasonable or unnecessarily restricted consideration of reasonable alternatives" (6T 1634-35).

G. Risk Analysis confirms that the Proposed Project is the most reasonable and prudent means to meet the Company's future power needs.

DTE Electric's Initial Brief, pp 73-76, recounted that Reasonable Risk is one of the six principles of DTE Electric's IRP planning,[81] and discussed how risk analysis was used to ensure the IRP's prudency and robustness (6T 1756-57).

Staff suggests that it has concerns, but does not articulate anything in particular that DTE Electric allegedly should have done differently (apart from vaguely suggesting to consider more or different alternatives), concluding that that the Company's analysis was "minimally effective," but suggesting that there could be a way to do something more "robust" (Staff Initial Brief, pp 20-21).

DTE Electric agrees that its risk analysis was "effective" (not just minimally so), and maintains that it was appropriately "robust." In addition to the extensive scenario/sensitivity analysis described in DTE Electric's Initial Brief and above, the Company's risk analysis consisted of four parts. The first was a Stochastic analysis,[82] which focused on maintaining or minimizing the Reasonable Risk principle. The second was an Analytic Hierarchy Process ("AHP") analysis,[83] which quantified and optimized the principles of affordability, clean, flexible and balanced, and reasonable risk. The third was a refresh of the Reference Scenario using the latest assumptions available (this is the 2017 Reference Scenario discussed above). Lastly, the Company completed

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[81] The six principles are: (1) Reliability; (2) Affordability; (3) Clean; (4) Flexible and balanced; (5) Compliant; and (6) Reasonable risk (6T 1606-1607).

[82] A Stochastic analysis is an advanced modeling technique that uses probability distributions of key drivers to evaluate portfolios (6T 1758). This results in a distribution of outcomes demonstrating the most probable outcome and the range of values around it (7T 1992). See Exhibit A-4 2nd Revised, section 12 for details.

[83] The AHP decomposes complex problems into a hierarchy of criteria and alternatives (6T 1760-6). "In layman's terms, the preferred plans are examined and debated two at a time" (7T 1792). See Exhibit A-4 2nd Revised, section 12 for details.

a Change analysis that considered how adaptable the plan is to new inputs and changes to the assumptions (6T 1757-58).

The Stochastic analysis evaluated four portfolios (DTE Electric 2017 IRP, Wind, Solar, and Demand Response) that were significantly different enough to warrant testing. The results were that the 2017 DTE Electric IRP of 1,100 MW combined cycle had both the lowest expected cost and the lowest economic risk (6T 1759-60, 1836-38).[84]

The AHP analysis evaluated the same four portfolios using five criteria (Cost, Environmental, Portfolio balance, Commodity prices, and long/short risk). Subject matter experts ("SMEs") who understand the complex issues rated the criteria in pairwise comparisons. SMEs also rated the likelihood of the five scenarios occurring, in pairwise comparisons. The AHP also included high and low load sensitivities as well as the high capital cost sensitivity. The results were that the combined cycle portfolio received the highest score. This demonstrates that the combined cycle portfolio is preferred and robust across all of the IRP portfolios under five weighted criteria and three sensitivities (6T 1760-62, 1825-27).

ELPC witness Mr. Lucas suggested, without support, that some SME responses were "outliers" that somehow invalidated the results. In response, the Company performed his suggested AHP adjustment removing both the high and low ratings for all of the SMEs. The result was essentially unchanged; in fact, the CCGT build plan improved slightly (6T 1827-28). Mr. Chreston also addressed Mr. Lucas' indicated concerns regarding the Portfolio Balance metric (6T 1828-29), the Market risk criteria calculation (6T 1829), the timing for purchases and sales (6T 1829-30), the commodity price risk metric (6T 1830-32), the scale used to rate portfolio alternatives (6T 1832-33), incorporating the scale into local weight calculations (6T 1834), and the

[84] Staff suggested a concern that appears to be based on inaccurate calculations (6T 1836).

capacity credit value for solar (6T 1835). Mr. Chreston further explained that Mr. Lucas also wrongly suggested that "the final step in DTE Electric's AHP relies on a fatally flawed calculation that is based on results from a single value from a single modeling run" (5T 807). Mr. Chreston explained:

> "The premise of IRP modeling is to use scenarios to capture the ranges of markets and input assumptions. In this way, uncertainty is addressed by using different scenarios, which DTE Electric incorporated in the IRP. In addition, the AHP analysis used the results of five modeling scenarios, not "a single value from a single modeling run." Variations in assumptions can be covered by using Stochastic analysis, which DTE also incorporated. The Company completed four different risk analyses: the AHP, the Stochastic risk analysis, scenarios and sensitivities (including running the 2017 Reference scenario with the latest assumptions), as well as the Change analysis. All four agreed that the CCGT in 2022 was the best plan for the Company" (6T 1835).

The 2017 Reference Scenario is similar to the Reference Scenario, but with updated assumptions, as indicated above. The best fit technology remains a CCGT (6T 1762). A few sensitivities were performed including 75% carbon reduction by 2040 (consistent with the Company's commitment to reduce greenhouse gas emissions), which is well-matched with the Proposed Project (6T 1763-64). A "No Build" sensitivity was also performed pursuant to the Commission's May 11, 2017 Order in Case No. U-15896, Attachment A, Part VII, Section A.15 in which energy and capacity needs are met through market purchases after the River Rouge, St. Clair, and Trenton Channel power plants are retired. The "No Build" sensitivity would be very costly and risky for customers, and is not economically viable (6T 1765).

The Change analysis used scenarios and sensitivities to measure how much the build plan would change depending on potential future events. The 2X1 combined cycle plant was the recommended build in the high gas price scenario, the high renewables sensitivities, and the high capital sensitivity. Other sensitivities similarly confirm that the Proposed Project should be built, with lower-than-expected load indicating only a slight delay, and higher-than-expected load increasing the need for timely construction to satisfy that load in 2022, as well as a potential need for additional capacity that could be mitigated by issuing an RFP, depending on how events unfold (6T 1766-67). Moreover, as DTE Electric transforms its generation fleet, there will be room for incremental DR, EE, Renewables, DER, and other options for capacity as these options continue to become more economic." (6T 1839).

The four types of risk assessment discussed above support the IRP as economic under a variety of situations, and is robust and prudent (6T 1767). Mr. Chreston further summarized why DTE Electric's proposed course of action is the most reasonable and prudent means to meet the Company's projected need for replacement capacity:

> "DTE Electric evaluated numerous resource options to determine the recommended combination of supply-side, demand-side, self-build, and market resources to meet its capacity needs. DTE Electric performed scenario and sensitivity analyses to test the robustness of the recommended plan to uncertainty around environmental regulations, resource cost and performance, fuel prices, load and other regulatory/legislative effects. In addition to scenario/sensitivity analysis additional risk analysis was conducted. The plan identified that significant additional capacity is needed beginning in 2022 to cover reserve margin requirements predominantly as a result of the projected retirements of River Rouge, St. Clair and Trenton Channel power plants from 2020 to 2023. DTE Electric anticipates the need for a 2X1 CCGT by June of 2022 to coincide with the MISO capacity market and potentially again in 2029. The plan, (Exhibit A-6) reflects increased energy efficiency and demand response resources, increased renewable generation and market purchases and is the most prudent plan" (6T 1768-69).

ELPC further argues that DTE Electric failed to consider the risk of the Proposed Project becoming a stranded asset, recounting arguments that were discredited above, and further asserting that companies want renewable energy, as reflected by GM announcing a goal of 100% renewable energy by 2050 (ELPC Initial Brief, p 35. See also MEIBC Initial Brief, p 7, and Staff Initial Brief, p 28, which notes that Dow Chemical, Pfizer and Praxair also have renewable energy procurement goals). However, such suggestions neglect that the real risk is in ignoring present reality in favor of speculating about the future. While the cited companies may have announced laudable renewable energy goals for the future, the present reality is that they are members of ABATE.[85] Therefore, these companies presumably support ABATE's effort to keep the Tier 2 coal plants operating, regardless of what they may say about wanting a green future. ABATE's effort to prolong the operations of aging coal plants should fail (as discussed above), and when it does, the Proposed Project is the only feasible way to provide reliable and affordable replacement electricity to customers. The proposed gas plant will also be highly flexible and have other favorable design attributes for an energy portfolio, as discussed in DTE Electric's Initial Brief and above, making any concern about it becoming a stranded asset unfounded and unrealistic.

H. Independent review further confirms that the Proposed Project is the most reasonable and prudent means of meeting the Company's future power needs.

DTE Electric's Initial Brief, pp 76-79, discussed Mr. Adkins' independent assessment of the Company's IRP models and processes (7T 1978). No other party's initial brief addressed this matter, so the Company simply incorporates its prior discussion on this topic. In further response to the modeling and risk assessment issues discussed above, however, the Company highlights Mr. Adkins' conclusion that:

> "The Company's data modeling and assumptions accurately reflect the Company's generation and planning operations. Furthermore, the Company has invested in developing a planning system that goes beyond what is simply adequate and presented a state of the art representation of the Company and the broader MISO market" (7T 1985).

Mr. Adkins also described the Company's Stochastic analysis and Analytical Hierarchy Process ("AHP"), as "timeless and considered best in class" (7T 1992), and opined that the Company's recommendation for a combined cycle gas plant in 2022 is the most robust and best resource decision:

[85] ABATE's Petition to Intervene in this case states at paragraph 2: "The current members of ABATE are . . . The Dow Chemical Company . . . General Motors Corporation . . . Pfizer – Kalamazoo; Praxair, Inc."

"As demonstrated by the preponderance of Combined Cycles in all future plans, ***the Combined Cycle plan is the most robust resource decision.*** The Combined Cycle demonstrates the least cost deviation across all scenarios and sensitivities. ***The Combined Cycle plan is the Company's best plan.*** Furthermore, this plan was confirmed by the group decision-making and the stochastic analyses.

* * *

"The decision to build a combined cycle plant is consistent with prevailing market conditions, as gas technology is the predominate economic resource of choice. A change in carbon regulations will not affect this decision. The Company is replacing coal with gas technology, which is consistent with the Clean Power Plan. A dramatic drop in renewable prices will also not affect this decision due to the firm capacity limitations" (7T 1993). (Emphasis added.)

Mr. Adkins agreed with DTE Electric's recommendation to build a combined cycle plant (7T 1994), and further explained that, in his professional and independent opinion, DTE Electric developed and used a best-in-class IRP process to reach that recommendation:

"Based on my experience, it is my independent opinion that ***the Company has developed a best in class Integrated Resource Planning system.*** One of the most fundamental and critical functions of an IRP process is the integration of data and analyses on a consistent basis. The Company has addressed this function by using a shared data system to support its long term and near term planning processes. The use of PowerBase to provide data to both the PROMOD and Strategist systems ensures an apples to apples analytical environment. ***Stakeholders can be assured that the data and analyses are sound and consistent.*** Furthermore, I have observed the IRP team's staff and found them to be highly motivated with a sharp attention to detail. Throughout the project the Company's staff was never satisfied with 'it is what it is.' Numerous times, I have worked with staff to gain a full understanding of the inner workings of the Strategist system and economic drivers of the analysis. The Company's staff are dedicated to quality. ***The Company's commitment to quality ensures the accuracy of both the data and the models.*** As a final thought, ***the Company has gone above and beyond reasonable efforts to assess the robustness of their preferred plan***. The Company has employed relevant scenarios and sensitivities complemented with Stochastics and Group decision-making. Three independent and rigorous tests for robustness were performed and proven consistent" (7T 1994). (Emphasis added.)

I. The Proposed Project will comply with environmental requirements.

DTE Electric's Initial Brief, pp 79-80, explained that the Proposed Project will comply with applicable environmental requirements (5T 1442-43. See also 5T 1473-74).[86] The Proposed Project will also use of state of the art emission control technology, resulting in the significant reduction in all emissions from the Proposed Project as compared to the retiring coal plants (5T 1444-47; Exhibit A-36 Revised estimates emissions over the life of the Proposed Project). Staff agrees that "it is reasonable to expect that the Proposed Project will comply with all applicable state and federal environmental standards, laws, and rules" (5T 183. See also Staff Initial Brief, pp 14-16).

DTE Electric incorporates the discussion in section III above in response to MEC/NRDC/SC's newly-announced (and frivolous) claim that the Commission allegedly cannot find that DTE Electric's Proposed Project complies with the Michigan Environmental Protection Act ("MEPA"), MCL 324.1701 *et seq*. (MEC/NRDC/SC Initial Brief, pp 10-13, 94-95).

Staff suggests that DTE Electric submit a list of all final environmental and/or construction permits, along with an affidavit stating that all necessary permits have been acquired (Staff Initial Brief, pp 15-16) DTE Electric disagrees because its initial filing outlined the applicable permits and Staff has not indicated a concern that anything in particular is missing. All required permits will also be publicly available. Permitting is also a dynamic and time consuming process that can take years and may require modifications (5T 1450). Redundant and time-consuming requirements with no added value should be rejected.

[86] The CON statute relevantly provides that the Commission shall grant the requested CON if, among other things:

> "(b) The information supplied indicates that the existing or proposed electric generation facility will comply with all applicable state and federal environmental standards, laws, and rules." MCL 460.6s(4)(b).

J. The Proposed Project would also provide benefits to local communities and the State of Michigan.

DTE Electric's Initial Brief, pp 80-81, explained that the Proposed Project will comply with applicable workforce requirements.[87] The Proposed Project will employ a construction work force of up to 520 laborers. The Company estimates that more than 90% of the craft labor will be comprised of Michigan residents who are members of various labor unions (6T 1620; 8T 2613-16; Exhibit A-45). Staff agrees that the Company will use a workforce in accordance with MCL 460.6s(4)(e). (Staff Initial Brief, pp 16-17). There appears to be no dispute with regard to this matter.

VII. THE PREPONDERANCE OF THE EVIDENCE SHOWS THAT THE PROPOSED PROJECT'S CAPITAL COSTS SHOULD BE RECOVERABLE IN RATES FROM THE COMPANY'S CUSTOMERS.

DTE Electric's Initial Brief, pp 82-83, discussed cost recovery. The CON statute relevantly provides:

> "The commission may allow financing interest cost recovery in an electric utility's base rates on construction work in progress for capital improvements approved under this section prior to the assets being considered used and useful. Regardless of whether or not the commission authorizes base rate treatment for construction work in progress financing interest expense, an electric utility shall be able to recognize, accrue, and defer the allowance for funds used during construction.". . . ." MCL 460.6s(12).

Staff supports the Company's proposed accounting and ratemaking treatment of its construction financing costs (Staff Initial Brief, pp 45-47), but at a slightly lower amount due to Staff's proposal to decrease the contingency to 1.9% ($17.8 million). (*Id*, pp 47-48). The Company maintains that Staff's proposed contingency decrease is inappropriate, as discussed in section V. A. of DTE

[87] The CON statute relevantly provides that the Commission shall grant the requested CON if, among other things:

> "(e) To the extent practicable, the construction or investment in a new or existing facility in this state is completed using a workforce composed of residents of this state as determined by the commission. . . ." MCL 460.6s(4)(e).

Electric's Initial Brief and above. Nobody else's initial brief discussed the cost-recovery CON.

Accordingly, and consistent with the Company's request in its currently-pending general rate case, Case No. U-18255, the Company requests to include in rate base the costs of construction work in progress ("CWIP") for the Proposed Project without an allowance for funds used during construction ("AFUDC") offset. The Proposed Project's average impact on customer rates is reflected on Exhibit A-46, which shows that the Proposed Project reduces rates using the Company's last Commission-approved revenue requirement (from Case No. U-18014) as a proxy (8T 2592-93).

MEC/NRDC/SC assert that DTE Electric did not perform a meaningful rate impact calculation. (MEC/NRDC/SC Initial Brief Initial Brief, pp. 84-86) In essence, MEC suggests that it would be more appropriate to compare the cost of the proposed plan to the cost of some other hypothetical course of action. MEC/NRDC/SC's suggestion is nonsensical. To the contrary, the Company appropriately calculated the rate impact as the change in cost from current operations versus the cost of operations after the Proposed Project replaces the tier 2 coal plants, which the Company presented on Exhibit A-46.

For CWIP incurred after the projected test year used in Case No. U-18255 (November 1, 2017 through October 31, 2018), the Company proposes accruing AFUDC until its next general rate case.[88] The proposed recovery will reduce the total capitalized cost reflected in rate base, and decrease future revenue requirements (5T 1498-99).

In summary, the preponderance of the evidence shows that the Proposed Project's total projected installed capital costs of $989 million should be recoverable in rates from the Company's

[88] DTE Electric reserves the right to use traditional accounting and rate making treatment of financing costs incurred during the construction period if the Commission does not approve the Company's requested accounting and rate making treatment of financing costs (5T 1498-99).

customers. Therefore, the Commission should issue the requested CON under MCL 460.6s(3)(d) pursuant to DTE Electric's request.

VIII. REQUEST FOR RELIEF

DTE Electric respectfully requests that the Commission:

1. Issue a certificate of necessity under MCL 460.6s(3)(a) that the power to be supplied by the Proposed Project is needed.
2. Issue a certificate of necessity under MCL 460.6s(3)(b) 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;
3. Issue a certificate of necessity under MCL 460.6s(3)(d) that the estimated total projected installed capital costs of $989 million 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; and
4. Grant DTE Electric such other and further relief as is just and reasonable.

Respectfully submitted,

DTE ELECTRIC COMPANY
Legal Department

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Dated: March 12, 2018

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

TANYA MARIA CARR, being duly sworn, deposes and says that on the 12th day of March, 2018, she served a copy of DTE Electric Company's Reply Brief, upon the persons on the attached service list via e-mail.

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TANYA MARIA CARR

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me this 12th day of March, 2018.

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Acting in Wayne County

SERVICE LIST
MPSC CASE NO. U-18419

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