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**
(e-file paperless)

MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S
INITIAL BRIEF

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

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DATED: March 2, 2018

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I. Introduction

In its application, the DTE Electric Company (DTE or the Company) asks the Michigan Public Service Commission to issue certificates of necessity (CON) with respect to its proposed plan to build a 1100 MW natural gas fueled combined cycle electric generation facility. (7/31/2017 Application.) DTE proposes that the project be located at its Belle River Plant with an estimated cost of $989 million. (*Id.*, p 5.)

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. The Company has satisfied the minimum standards at the time the application was filed for an IRP that suggests a need for 1100 MW by 2022. (Exhibit A-4.) The IRP compared the proposed plant to 5 other resource options. (7/31/2017 Application, p 5.) Staff believes DTE has met the minimum requirements in the statute for issuing the CONs, as discussed in greater detail below. While Staff believes the proposed project is in the interest of ratepayers, due to its ability to provide affordable capacity and reduce emissions versus coal, Staff expects that future CON requests will contain a more robust analysis of resource alternatives now that the regulatory framework has more guidance. To achieve that, DTE will need to take immediate action to rectify deficiencies in its analysis by March 2019 to avoid setting into motion the need for another build in 2029, without properly exploring all of the alternatives.

II. The Regulatory Framework for DTE's Certificate of Necessity (CON) Request

In this proceeding, DTE seeks to take advantage of a provision in MCL 460.6s(1) that allows it to request a Certificate of Necessity (CON) preapproving its plan to build an electric generation facility. DTE filed its CON case after 2016 PA 341 took effect on April 1, 2017, but before the MPSC could provide guidance on the new IRP standards under MCL 460.6t. Staff has evaluated DTE's application in light of the regulatory guidance available at the time it filed its application.

2016 PA 341 (the Act) directed the Commission to develop IRP filing requirements and IRP modeling parameters pursuant to Section 6t(1) of the Act. 11/21/2017 Order, MPSC Case No. U-18418, p 2. (Attachment A.) On November 21, 2017, the Commission issued its Order in MPSC Case No. U-18418 for the modeling parameters with input from the Michigan Agency on Energy (MAE), the Department of Environmental Quality (DEQ), stakeholders, and other interested entities. On December 20, 2017, the Commission issued its Order in MPSC Case No. U-15896[1] for the IRP filing requirements. (Attachment B.) 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 includes discussion of the guidance to illustrate the deficiencies in DTE's IRP analysis, and its expectations for future applications.

[1] MPSC Case No. U-15986 is a docket that continues to update IRP requirements, which are evolving based on changes in Legislation. Thus, the case at hand complies with the prior guidelines, but not the most recent 2017 guidelines.

Through this proceeding, the Commission will decide how much of the $989 million, if any, it will preapprove for the construction of this facility. Act 341 requires the Commission to grant a utility a CON preapproving its estimated project costs if the utility meets five statutory requirements under MCL 460.6s(4). For the costs of the proposed construction to be recovered in rates, the Company must meet the following five requirements: (a) that the utility has demonstrated a need for that power, (b) that the proposed generation will comply with state and federal environmental regulations, (c) that the cost of power is reasonable, (d) that the proposed construction is the most reasonable and prudent option when considering other options, and (e) that the workforce utilized for the new construction be composed of residents of the state in which it is built. MCL 460.6s(4)(a)-(e). The Commission may also consider other project costs as well as the costs of alternatives raised by intervening parties. MCL 460.6s(5). Intervenors point to alternatives that the Commission has the leeway to consider in this matter, and that also should be addressed in the March 2019 IRP.

If the Commission grants DTE's CONs in this case and preapproves costs for its proposed project, its decision will meaningfully affect future ratemaking proceedings because MCL 460.6s(9) guarantees DTE recovery of these preapproved costs through retail rates. DTE's rates will be adjusted to reflect the project costs preapproved in this case once DTE begins operating the units (i.e., the project is used and useful) and the Company files a rate case to recover its costs. See MCL 460.6s(9). At that time, the Commission may not prevent DTE from recovering costs that it "incurs in constructing . . . an electric generation facility . . . for which a certificate of necessity has been granted, if the costs do not exceed the costs approved by the commission in the certificate." *Id.*

A decision approving a CON for DTE will also meaningfully affect future ratemaking proceedings by allowing DTE to defer certain financing interest expenses. MCL 460.6s(12) provides, in part, "The commission shall allow financing interest cost recovery in an electric utility's base rates on construction work in progress [CWIP] for capital improvements approved under this section prior to the assets being considered used and useful." The statute does not require the Commission to allow DTE to recover all CWIP in base rates before the assets are used and useful; the statute only applies to CWIP financing interest cost. Whether or not DTE is allowed to incorporate CWIP financing interest expenses in base rates, DTE may "recognize, accrue, and defer the allowance for funds used during construction [AFUDC] related to equity capital." *Id.*

III. The Burden of Proof

"[I]n matters before the Commission where statutory law is silent regarding the correct quantum of proof needed to review a utility's costs, the Commission assesses those costs using the preponderance of the evidence standard adopted in civil cases." *In re Detroit Edison Co on Remand*, MPSC Case No. U-15768, 10/17/2013 Order, p 16, citing *Residential Ratepayer Consortium v Public Service Comm*, 198 Mich App 144, 149 (1993). And the Commission has held that "Section 6s did not alter the burden of proof in an administrative proceeding before the

Commission." *In re Indiana Michigan Power Company's Application for a Certificate of Necessity*, MPSC Case No. U-17026, 1/28/2013 Order, p 33. DTE, therefore, has the burden of proving its case by a preponderance of the evidence.

Preponderance of the evidence means "such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth." *People v Pugh*, 48 Mich App 242, 245 (1973). The Michigan Supreme Court has explained how administrative agencies should apply this standard:

> The comparative degree of proof by which a case must be established is the same in an administrative as in a judicial proceeding – that is, a preponderance of the evidence. It is not satisfied by proof creating an equipoise, but it does not require proof beyond a reasonable doubt. No essential issue may be left to surmise, guess, or conjecture, for an administrative body cannot base an award or decision upon conjecture or speculation, although a determination may properly be based on circumstantial evidence. [*Dillon v. Lapeer State Home & Training Sch*, 364 Mich 1, 8; 110 NW2d 588 (1961) (quotation marks and citation omitted).]

In sum, if DTE proves its case by a preponderance of the evidence, the burden of proof shifts to the other parties to challenge that evidence. In *In re Detroit Edison Co's Application to Increase Rates*, 1/11/2010 Opinion and Order, MPSC Case No. U-15768, pp 35-38, the Commission held that once a utility has satisfied its initial burden of proof, another party "may challenge that evidence and present evidence of unreasonableness" but the other party "has the burden to demonstrate its position is correct." *Id.*, p. 38.

IV. Background

Act 341 requires this case to be completed within 270 days of DTE filing its application. Along with its application, DTE submitted an IRP for a planning period of 2017 through 2040, evaluating reasonable and prudent combinations of resources to meet future scenarios. (Application, p 4.) DTE's IRP concludes that it will need substantial capacity and energy beginning in 2022. DTE projects that it will retire River Rouge, St. Clair and Trenton Channel power plants between 2020 and 2023. (*Id.*) This will cause a shortfall that DTE submits is best filled by its request for an 1100 MW NGCC at Bell River. (*Id.*) Given the information it was able to analyze within the statutory timeframe, Staff agrees that DTE has satisfied the requirements of Act 341 with reservations regarding the IRP, especially with respect to the expected robustness of future filings.

Staff encountered several stumbling blocks within the 270 timeframe, such as the need for numerous motions to compel, filed by multiple parties, and the initial withholding of bid information that was requested in discovery by Staff, as statutorily required to be reviewed. These delays cumulatively resulted in Staff's request to extend the schedule, which was granted by the ALJ and reversed by the Commission. At cross-examination, the ALJ requested that the parties agree on an online or key issues for this brief to assist the Commission in this case. Staff attempted to comply with the Commission's request. Unfortunately, the Company did not seem willing to cooperate with Staff and the other parties to come to a consensus.

V. Staff's Position

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. "[T]he Commission is required to limit a CON to reasonable and prudent costs if the record shows that costs are excessive." *In re Indiana Mich Power* Co, MPSC Case No. U-17026, 1/28/13 Order, pp 30–31. DTE has satisfied the current CON requirements by demonstrating through its IRP that the power is needed and that its proposed facilities are the most reasonable and prudent means of meeting that need. DTE's IRP also satisfies with the minimal language of the statute (MCL 460.6s(11)) taken with the Public Convenience and Necessity Application Instructions approved in the December 23, 2008 Order in Case No. U-15896. (Attachment C.) As long as DTE can complete the project within budget, DTE should be allowed to recover its proposed facilities' estimated capital and financing costs through rates.

A. The Company has satisfied the minimum requirements of MCL 460.6s(3).

The Legislature specified in MCL 460.6s(3)(a)-(c) the requirements that a utility must meet before it can be granted a CON for the building of a new generation facility. For the three certificates requested by the Company in this case the Company must prove: (1) that the power to be supplied by the proposed construction is needed, (2) that the proposed construction represents the most reasonable and prudent means of supplying that power and (3) that the estimated capital costs should be pre-approved in rates. Staff submits that under the applicable guidance when the application was filed, DTE has met the requirements for the 3 CON requests.

1. DTE Electric presented an undisputed need for power through its IRP in compliance with MCL 460.6s(3)(a).

Examining the Company's application and attached IRP, and applying the guidance available at the time the application was filed, Staff's Director of the Electric Reliability Division, Paul Proudfoot, testified that the Company demonstrated that the 1100 MW of power that will be supplied from its proposed construction is needed. (5 TR 181.) In support of the application, Company witness Kevin Chreston provided testimony about the Company's IRP and also sponsored the Company's Exhibit A-6 containing the IRP. According to Chreston, planned retirements of River Rouge, St. Clair and Trenton Power Plants between 2020 and 2023 will result in a significant capacity shortage beginning in 2022, starting with a shortfall of 472 MW increasing to 1,266 MW. (6 TR 1718.)

Further, witness Chreston explained that to calculate these shortfalls, the Total Planning Resources was subtracted from the projected total Planning Reserve Margin (PRMR). (6 TR 1719.) Chreston provided the 2022 and 2023 PRMR and Total Planning Resources in his testimony and subsequent years in the Company's Exhibit A-7. (6 TR 1720-1721.)

The Environmental Law and Policy Center, the Ecology Center, the Solar Energy Industries Association, Vote Solar, and the Union of Concerned Scientists (collectively ELPC) supports the Company's assertion that it needs new capacity given the planned retirements of aging coal units. (5 TR 910-911.) Likewise, MEC-NRDC-Sierra Club contests the Company's underutilization of other resources in its IRP, such as demand response, capacity import and energy efficiency to displace the need for a new-build combined cycle natural gas plant, it does not disagree that the need for capacity will exist with the planned retirement of the Company's coal plants.

While the parties are in agreement that the energy is needed, they are not in agreement that the IRP is as robust as it should be. Staff, for one, believes that the IRP meets minimal requirements, but that in future CON applications, it expects to see better analysis from an IRP. Based on his review of the information presented in this case, Staff witness Proudfoot emphasized that he has numerous reservations about the IRP. Proudfoot explained that the Company overlooked and underutilized Staff-identified supply and demand resources in its IRP that, in the aggregate, could partially displace the Company's proposed plant. (5 TR 181.) In fact, Staff requested the Company to include Staff's supply and demand resources that could have mitigated defects in the Company's IRP, in a combined, cohesive analysis. (Exhibit S-1.10.) However, the Company refused and indicated that its low load sensitivity serves as an adequate proxy for Staff's request. (5 TR 214.) Staff maintains that it is unclear whether the low load sensitivity serves as an adequate proxy for its combined supply and demand resource scenario. (5 TR 215.) Nonetheless, if the Company's comparison was in fact accurate, it would eliminate the need for additional large generation throughout the remainder of the study period. (5 TR 215-216.) Because the Company did not run Staff's alternative scenario in a timely manner, the actual results of such inputs were not able to be fully evaluated by the Staff.

Staff supports the approval of DTE's requested CON that the power to be supplied is needed with the following caveats. The Company conducted its IRP analysis in accordance with the guidance provided by the Commission's December 23, 2008 Order in U-15896, in which the Commission provided the procedures to implement section 6s of Public Act 286 of 2008 and provide guidance to regulated utilities within the state as to the filing of IRPs. (Attachment C.) However, the Commission issued its Order implementing Section 6t of Public Act 341 of 2016 on November 21, 2017 in MPSC Case No. U-18418 (Attachment A) as well as the Section 6t filing requirements issued on December 20, 2017 in MPSC Case No. 15896. *In re the Commission's Own Motion to Implement MCL 460.6s(10) and (11)*, 12/20/2017 Order, MPSC Case No. U-15896. (Attachment B.)

Staff's recommendation to approve the CON requests is based on the Company's satisfaction of the requirements of Section 6s under the guidance available at the time the application was filed. It does not negate the standards that have now been issued. Section 6t of 2016 PA 341 requires all regulated utilities in the state to file IRPs within two years of the effective date of the act. Staff maintains that, though Staff supports approval of the requested CONs in this case, all the deficiencies identified by Staff in the Company's present IRP must be addressed in its IRP to be filed in accordance with Section 6(t) of Act 341. Staff submits that the IRP complies with the requirements of Section 6s(11), but that it would fail if it were simply refreshed and refiled under Section 6(t).

To determine whether the Company's CON requested pursuant to MCL 460.6s(3)(b) should be approved, Staff's analysis focused on the whether the Company satisfied the requirements of MCL 460.6s(4)(d), that the proposed project represents the most reasonable and prudent means to meet the power need relative to alternative proposals. At the outset, Staff highlighted that the Company failed to meet the IRP standards developed under the process required by 2016 PA 341 and adopted by the Commission in its November 21, 2017 Order in MPSC Case No. U-18418. (5 TR 185; Order, Attachment A.) However, Staff acknowledges that Commission guidance with respect to the new IRP standards was not available to the Company at the time it was conducting its IRP analysis due to the timing of the present case and the November Order. (*Id.*)

As emphasized above, Staff strongly recommends the Commission order the Company to address Staff's identified issues and shortcomings in DTE's current IRP analysis in all of its future IRP and CON filings. Given this important caveat, Staff recommends that the Commission hold that the Company met the minimum IRP standards required for approval. Given the extent of the deficiencies in the Company's IRP detailed elsewhere in this brief, however, Staff notes that the Commission could reasonably deny the Company's request for this CON and require a robust analysis in accordance with the Commission's November 21, 2017 Order in MPSC Case No. U-18418. (Attachment A.)

2. DTE's requested CON that estimated capital and financing costs be recovered in rates from the Company's customers should be approved under MCL 460.6s(3)(d).

The Commission's granting of a CON under MCL 460.6s(3)(d) is statutorily conditioned upon the Commission's determination that the estimated cost of power from the proposed project is reasonable, pursuant to MCL 460.6(s)(4)(c). To this end, Staff asserts that it finds the proposed project costs, after removal of $37.2 million in contingency costs (5 TR 204-206) to be reasonable. After Staff's contingency adjustment, the proposed project cost is $951.8 million. (5 TR 184.) Staff continues to have concerns about the Company imposing limits in its Request for Proposals (RFPs) for power purchase agreements (PPAs) that may have unfairly excluded some respondents' competitive bids from the process, as discussed below in Section V.B.1., of this brief. (5 TR 184.) The Company, however, demonstrated to Staff that it used a competitive bid strategy to contract its proposed project. (*Id.*) Thus, Staff supports the granting of a CON pursuant to this provision.

B. The Company has minimally complied with MCL 460.6s(4).

1. The proposed project is based on a contract that is the result of a competitive bid process.

DTE demonstrated to Staff that it engaged in a competitive bid process to contract its proposed project. "The Company demonstrated its strategy through a mutually agreed upon meeting to review bids the Company received in responses to request for proposals (RFPs) for both the power island equipment (PIE) and full wrap engineer, procure, construct (EPC) services." (5 TR 183.) Staff Exhibit S-1.4 illustrates the Company's response to Staff's discovery, which provides significant detail regarding its competitive bid strategy used in contracting the proposed project. The Company explored three different contract strategies for the proposed project.

First, the Company explored a balance of plant (BOP) engineer, procurement, and construction (EPC) contracting strategy. This strategy would provide a fixed price agreement for the balance of plant with owner furnished power island equipment (PIE). (8 TR 2607-2608.) Second, it explored a fixed-price full wrap option where the contract for the proposed project would include both the PIE and BOP in one fixed-price contract. Third, the Company evaluated an RFP for the acquisition of existing plants or power purchase agreements (PPA) as an alternative to a self-build project.

Staff has ongoing, significant concerns with the way that the Company conducted its RFP process and strategy. In particular, the 7-year restriction placed upon PPAs, as a maximum contract limit, is disconcerting to Staff. The 7-year timeframe is unfairly restrictive, creating an inequality between PPA's and the proposed project in terms of financing. (5 TR 200.) These concerns are echoed by Midland Cogeneration Ventures, LP (MCV) witness Kevin Olling in testimony. (5 TR 610.) The Company argues that limiting the PPA term to seven years appropriately mitigates some of the risks associated with long-term PPA's and that even the most well written contracts cannot mitigate the risks inherent in contracts. (6 TR 1626-27.) Staff does not agree with the Company's rationale for several reasons.

Staff understands the risks associated with long-term contracts. However, "[t]hose risks could be addressed through a well-written contract." (5 TR 200.) Additionally, ratepayers will incur significant financial risk if the Company's proposal is adopted, and that fact should not be overlooked. (*Id.*) Gas prices may fluctuate, and an approximately one billion-dollar plant with a 30-year operating life expectancy is a long-term investment.

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. Therefore, Staff recommends the Commission accept the contracting strategies as having sufficiently considered the available new build and PPA options in this case only. Staff recommends that the Commission acknowledge that such limiting strategies should not be considered as precedent setting. In the future, Staff would expect parameters for an RFP that to put bidders on an equal footing with the Company.

2. DTE's proposed facilities will comply with state and federal environmental laws.

DTE filed it application in this case under the guidance provided in MPSC Case No. U-15896, where the Commission adopted Public Convenience and Necessity Application Instructions. One requirement in that order compels a utility to provide "[a] description of all major State, Federal, and Local permits required to construct and operate the proposed generation facility . . . in compliance with State and Federal environmental standards, laws and rules," *In re the Commission's Own Motion to Implement MCL 460.6s(10) and (11)*, 12/23/2008 Order, MPSC Case No. U-15896, p 5. (Attachment C.)

DTE Electric has indicated that it will comply with all state and federal environmental laws, as required by law. Staff has some concerns about the manner in which DTE proposes to submit its proof as discussed in greater detail below.

Staff Exhibits S-1.2 and S-1.3 provide an environmental permit matrix and permit descriptions required for the proposed project. The Company has not indicated the need for additional infrastructure outside of the project site boundary. (5 TR 1475.) Additionally, Staff recommended that the Company submit a list of all final environmental and/or construction permits that are obtained for the construction and operation of the proposed project accompanied by an affidavit stating that all necessary permits have been acquired. (5 TR 198-99.)

In its rebuttal, the Company rejects a portion of Staff's recommendation. Although the Company does not object to submitting a final list of all permits that are obtained for the construction and operation of the proposed project, it objects to the inclusion of an affidavit stating that all necessary permits have been acquired. The Company states that DTE Electric is obligated to comply with all applicable environmental laws and regulations and that the appropriate permits will be acquired from the appropriate local, state or federal agencies and should be assumed to be following the law. (5 TR 1450.) The Company also states repeatedly that, if Staff has concerns that necessary permits were not identified, it should raise those concerns specifically. (5 TR 1433, 1450.) The onus is on the Company to identify and comply with state and federal regulations, and Staff believes the affidavit is an appropriate vehicle for satisfying that requirement.

It is reasonable to require the Company to file both a final list of permits obtained for the construction and operation of the proposed project as well as an affidavit affirming its due diligence in the matter. Likewise, such a request to include an affidavit is not overly burdensome. The Company is ultimately responsible for ensuring the proposed project is constructed and operated in a safe manner that is compliant with all local, state and federal regulations. A sworn affidavit affirms the Company is intending to do so and that it will keep a watchful eye over its full wrap EPC contractor to ensure that all regulations are appropriately adhered to and provide a level of accountability in the matter. Therefore, Staff recommends that the Commission require a final list of environmental permits along with an affidavit stating all necessary permits have been acquired to be filed by the Company in the docket for this case.

3. DTE Energy will utilize a workforce composed primarily of Michigan residents as required by MCL 460.6s(4)(e).

Staff is satisfied by the Company's presentation that the workforce contracted to complete work on the proposed project will be composed primarily of Michigan residents. The Company specifically identified 18 labor unions from which it can draw its workforce. (5 TR 186.) Furthermore, Company witness Dan Fahrer testified that more than 90% of the craft labor required for this project will be composed of Michigan residents. (8 TR 261-2615.) Staff believes that the Company has adequately satisfied the statutory requirements of MCL 460.6s(4)(e).

4. The Company will comply with statutory reporting requirements.

The Company has indicated that it will comply with the reporting requirements identified in MCL 460.6s(7). The Company has proposed to file a narrative report on an annual basis with the Commission. (5 TR 2014; Exhibit S-1.9.) Staff has recommended that the Company file biannual review filings posted to the docket in this case, if the Commission ultimately grants approval for this CON. At a minimum, Staff recommends that the report include the status of the proposed project with any cost and schedule updates including any deviations from the originally estimated cost and schedule. (5 TR 206.) Staff recommends that the Commission require the report to provide sufficient detail regarding scope, timing and cost to allow for a transparent dialog with DTE throughout the duration of the project until the project reaches full commercial operation. (5 TR 207.) No parties have disagreed with Staff's recommendation.

C. The Company's IRP complies with the minimal standards under Act 341 at MCL 460.6s(11) under the guidance available at the time of the filing of the application with certain qualifications.

1. The Company included a long-term forecast of the electric utility's load growth under various reasonable scenarios as outlined in Section 6s(11), despite Staff's preference for a more robust analysis.

The Company developed five scenarios for the July 2017 IRP: (1) a reference case, (2) high gas prices, (3) low gas prices, (4) emerging technology, and

(5) aggressive CO_2, in compliance with MCL 460.6s(11)(a). (5 TR 208.) The Company included a long-term load forecast under these scenarios with various sensitivities and a negative 0.1% compound annual growth rate (CAGR) over the 2015 to 2040 period. Sales are expected to decrease over the period. (5 TR 225.) Staff determined that the long-term load forecast growth rates were consistent with other load growth projections in the region. (5 TR 226.)

The Company provided short-term 2017 to 2022 and 2016 to 2021 annual fuel forecasts, including all other fossil fuels, for the reference scenario. (*Id.*) The Company also included projected natural gas fuel costs for the reference, high gas and low gas cases. These were found to be consistent with those of other industry projections with the exception of the high gas case projections (5 TR 227), as required by MCL 460.6s(11)(b) in the IRP. The Company's (inconsistent) long-term natural gas price forecasts for the high gas scenario, has a CAGR which is 1.6% lower in price than the Energy Information Agency (EIA) high gas case. (5 TR 232.) If the growth rate of prices were to track that of the EIA high gas prices, this could mean that the Company's proposed project is not the most reasonable and prudent choice. The Company should have used higher prices in its natural gas high price case.

The Company's claim that the EIA high gas case is 8.3% rather than the 9.3% presented in Staff's Second Corrected Exhibit S-2.3 (S-1.3) is incorrect. Company witness Chreston, disputed Staff's analysis of the high gas scenario stating "Specifically, the calculation for the "CAGR" for the EIA high gas price case is 8.3%

on his work paper while it is 9.3% in his Exhibit S-1.3." (6 TR 1816.) Witness Chreston also stated that Staff witness Olumide Makinde's work paper and Exhibit S-1.3 did not match for the DTE high gas CAGR.

> In the exhibit, the value shown was 7.7% while in the work-paper it was 4.4%. However, I was able to recreate his exhibit value of 7.7% for the DTE CAGR simply by deleting the 2036 High Gas value of -58.08% (cell T25). (6 TR 1817.)

Witness Chreston stated that the Company was unable to recreate the 9.3% CAGR in exhibit S- 1.3(S-2.3):

> The Company's conclusions are that the correct number for the Witness Makinde's CAGR calculation for the EIA high gas case should be 8.3% and the correct number for the CAGR calculation for the DTE case should be 7.7%. This would put the difference between the two cases at 0.6% instead of 1.6%. (6 TR 1817.)

Staff rejects the unsupported, incorrect claim that the EIA high gas case should be 8.3% rather than the 9.3% presented in Staff's Second Corrected Exhibit S-2.3 (S-1.3).

Staff took the average of the EIA high gas case annual growth rate over the same number of years as that of the Company's high gas case to derive the 9.3% (lines 2 to 20 of column (d) of Second Corrected Exhibit S-2.3). The difference between the two cases is 1.6% as shown in Exhibit S-2.3. Witness Chreston is incorrect that CAGR difference should be lowered to .6%, and Staff is correct that the Company has not adequately projected a high gas price sensitivity and the Company is underestimating the net present value of revenue requirements in the event that gas prices rise closer to the EIA's high gas price scenario compared. (5 TR 232.)

a. The Company should to update its high gas price sensitivity with a corrected high gas price forecast in its March 2019 IRP.

For its March 2019 IRP, the Company should update its high gas price sensitivity with a higher gas price forecast consistent with the Commission's recently approved Michigan Integrated Resource Planning Parameters (MIRPP) in Case No. U-18418, as specified for the high gas price sensitivity in the Business as Usual Scenario. The MIRPP specifies a high gas price sensitivity used to "(i)ncrease the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period." The Commission could recommend that an update be posted in this docket, or in the alternative that it must be in the March 2019 IRP. (5 TR 233).

b. Staff has concerns with the Company's risk analysis in the July 2017 IRP.

Staff is concerned with the lack of a robust and nuanced Company risk analysis. "Staff views the purpose of a risk assessment as being two-fold. First, a risk assessment can be used to determine a build plan's sensitivity to specific future circumstances. Second a risk assessment can provide relative information about the potential cost of a future outcome being very different than expected." (5 TR 212-13.) The Company's stochastic analysis was reported and applied as a comparison to three alternate build plans rather than an adequate evaluation of the risk exposure of the preferred plan. The analysis can be applied to alternative builds. In order to gauge the proposed project's exposure to risk the impact of changes in the input assumptions due to unexpended futures imposed on the proposed build plan should have been analyzed. Thus, if the Company concluded that the least-risk build is the proposed plan, over alternative builds, it should have analyzed that risk if it were to alter certain eventualities within that plan, such as the timing of the build or hedging gas costs through the use of supplemental alternatives. (5 TR 235.) As Staff witness Makinde stated:

> Stochastic risk assessment measures the possible impact selected uncertainties can have on an optimal build plan when, exposed to variances in the specified uncertainties- such as increases or decreases in load over a period of time and/or intervals of time- when build plans cannot be reversed.
>
> Understanding risk and the associated monetized impact helps to determine if the least cost plan is truly the best plan, when coupled with the selected uncertainties, associated probabilities, and their interplay. This understanding gives decision makers the ability to alter plans by reducing and/or minimizing exposure to the risk variables in the future. Allowing for small alterations that do not drastically deviate from the optimized plan may ultimately limit the ratepayer's exposure to risk inherent with that plan. (5 TR 236.)

Failure to quantify the impact of input variables on the proposed project made the stochastic analysis less useful than it otherwise could be. Likewise, understanding if and how risk exposure can be cost-effectively minimized can help to "determine if the least-cost plan is truly the best plan when coupled with the understanding that the future is unknown." (5 TR 213.) While the analysis was minimally effective, a more robust assessment "creates an understanding of the types of investments that may insulate the ratepayer from exposure to risk and the related costs." (Id.)

2. The IRP evaluated the type of generation technology being proposed and the planned capacity, even though Staff would have preferred more scenarios and sensitivities to see if the plant could be deferred.

The Company's proposed project consists of an advanced class natural gas combined cycle (NGCC) electric generation facility with a nameplate capacity of approximately 1100 MW. The Company analyzed this option extensively in its IRP analysis presented in Exhibit A-4. Table 10.10.1 of the Company's IRP illustrates all the resource options that were evaluated through its IRP process. The proposed project was analyzed in each of the four model types used by the Company in its IRP process, the technical screening model, the levelized cost of energy (LCOE) model, the Strategist model and the PROMOD model.

Staff and Intervenors have expressed many concerns related to the IRP analysis of the proposed project. Staff, MEC-NRDC-SC, and ELPC express concerns with the Company's modeling parameters. These concerns include, but are not limited to, range of gas price forecasts, limitations on resource sizing, restrictions on the amount or number of resources of a type the models could select, scenario construction, rollout and timing of alternative resources, and overall risk analysis. The reason for the Staff and intervening parties' reservations regarding the Company's modeling parameters is that any one of these concerns can create a bias in the model that will tend to favor a specific resource, in this case the proposed project.

The Company's model will not choose to overbuild capacity; therefore, it is appropriate to more heavily scrutinize the Company's scenarios, specifically the development times for certain alternative resource programs, sizes of resources, and the number of resources available for the model to select. Overbuild of capacity may have an appropriate role where ramp up is necessary technologies and resources that could alter or displace a need for additional, more costly capacity. Although Staff and others have pointed in detail to a number of valid concerns in testimony and cross-examination, Staff believes the Company met the minimum standard for an IRP analysis that was available at the time of filing.

2016 PA 341 directed the Commission to develop IRP filing requirements and IRP modeling parameters. The Commission rapidly completed both tasks as directed by the Legislature. On November 21, 2017, the Commission issued its Order in MPSC Case No. U-18418 (Attachment A) for the modeling parameters. The Legislature directed the Commission at Section 6t(1) of the act to issue modeling parameters, with input from the Michigan Agency on Energy (MAE), the Department of Environmental Quality (DEQ), stakeholders, and other interested entities. (Order, p 2.) On December 20, 2017, the Commission issued its Order in MPSC Case No. U-15896 for the IRP filing requirements (Attachment B.) Both orders were issued in accordance with Section 6t(3), which states that 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."

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.

3. The Company accounted for alternatives, such as its current demand response, load management, energy waste reduction and renewable energy portfolio, but is capable of much more.

a. While minimally acceptable, Staff is concerned with DTE's renewable energy and distributed energy portfolio and recommends that the Commission require the Company ramp up both programs.

Staff' assessment of DTE's proposed renewable energy (RE) portfolio in this case is that it should have been more frank and thorough. Staff acknowledges that the portfolio meets a minimal standard by which the Company's request for a CON for its proposed NGCC plant should be approved. Staff recommends also that the Commission direct the Company to increase its RE standards for the future IRP submissions.

With respect to renewable energy the primary areas of contention between DTE and Staff are cost assumptions, capacity factor, MISO capacity credit and errors within the model. The overarching area of agreement between intervening witnesses and Staff is that DTE should be actively seeking out ways to take advantage of wind production tax credits (PTCs) and solar investment tax credits (ITC) while they are available. The testimony of intervening witnesses in the record merits Staff addressing certain aspects in this brief, especially as we look toward the March 2019 IRP, which will have more stringent requirements.

While Staff agrees with many of the Intervenors criticisms regarding RE, it would be hyperbolic to state that DTE's solar and wind capital cost assumptions are vastly out of line. Company witness Chreston points out in rebuttal that the solar levelized cost of energy (LCOE) utilized in the modeling was in-line with IHS-CERA, Navigant and the National Renewable Energy Lab ATB forecasts. (4 TR 1810.) 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 Witness Beach's solar assumption, the two cost projections are close resulting in a 4.3% difference. (4 TR 1812.)

Michigan Energy Innovation Business Council (MEIBC) witness Hunt discusses levelized costs of wind and sites EIA's Annual Energy Outlook, Lazard and others with levelized cost of energy (LCOE) prices in the $43-$56/MWh range (5 TR 637) after the Production Tax Credit has lapsed while DTE Electric utilized a $70/MWh LCOE over the same time-period. These LCOE values are based on an assumption of an average capacity factor of 42.6%. (5 TR 636.) Several parties, Staff included, stated that the Company should take advantage of federal PTCs prior to the sunset of the tax credit; however, capacity factors in the 41%-42% are only achievable in Michigan if wind development can continue to take place in the thumb region. Staff believes it is also reasonable for the Company to utilize lower capacity factors for wind as current moratoriums and public backlash in the Thumb region may exclude future wind development in the region.

Company witness Schroeder testifies that the Company expects much of the wind development through 2025 to take place outside of the Thumb region due to Huron County voter referendum and local resistance. (8 TR 2474.) It is reasonable to assume that future wind development will take place in regions of the State that have lower capacity factors in the range of 32-35%. (5 TR 461.) This will cause an increase in the LCOE of wind.

In summary, with respect to renewable costs, Staff is not persuaded that DTE's renewable costs projections are inappropriate. Staff agrees, however, with Intervenors that the Company should take advantage of federal tax credits and that utilizing smaller blocks of wind and solar would have resulted in model scenarios that build out these resources earlier (as discussed below). The Commission should direct the Company to use smaller blocks of wind and solar in its upcoming March 2019 IRP case.

Concerning wind costs, specifically, MEC witness Allison points out that DTE Electric under-estimates the net present value of the wind production tax credit by $51 million. (5 TR 470.) This is the result of a calculation error that utilizes the incorrect base year for the net present value analysis. Witness Allison also critiqued the Company's decision to model 1000 MW ICAP blocks of wind (UCAP of 156) and 502 MW ICAP of solar (208 MW UCAP) in the base case. (5 TR 478.) Additionally, he states that DTE Electric configured the Strategist model to not pick any resources prior to a capacity need if minimum reserve and reliability criteria were met prior to 2022. (5 TR 479.) The combination of the above factors resulted in the model failing to select renewable resources that could take advantage of full tax benefits or be incrementally and gradually built to address pending capacity needs in 2022. (5 TR 480.) The result is an unfair comparison of generation resources that could potentially offset the need for a large combined cycle plant.

Staff agrees with MEC witness Evan's testimony and recommends 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. Witness Evans showed that Strategist would select wind and solar prior to 2022 by running the model with blocks of 100 MW wind and 50 MW solar increments as opposed to 1000 MW and 505 MW. Additionally, he changed the model's utilization of energy efficiency resulting in an alternative optimal portfolio that pushes construction of the proposed NGCC plant out to 2029 with greater renewable utilization. Combined with other corrections and assumptions, including the correction of the base year wind PTC accounting as discussed above, these changes resulted in a $1.882 billion (NPV) ratepayer savings. (5 TR 558.) Additionally, ELPC witness Beach shows that a Renewable Energy and Energy Efficiency Portfolio could offset the entire proposed plant until 2027 at $1.2 billion savings to rate payers when compared to DTE's reference case. (5 TR 949.)

MEC witness Jester addresses the Company's failure to analyze customer requested renewable programs in the IRP analysis. (5 TR 432.) 2017 PA 342, Section 61 specifically requires utilities to develop these programs and as ELPC witness Lucas discusses in his direct testimony, Michigan-based companies such as General Motors, Google, Amazon and Walmart have all announced 100% renewable energy plans (5 TR 670.) Additionally, Cargill, Dow Chemical, Eaton Graphic Packaging, Pfizer, and Praxair all have renewable energy procurement goals (5 TR 989.)

Staff and Intervenors testified to the Company's failure to include currently contracted and potential future Public Utility Regulatory Policies Act (PURPA) projects in its IRP. Witness Jester states that the Company currently has a PURPA portfolio consisting of 5 MW of hydro contracts, 60.1 MW of waste-to-energy contracts, and 39 MW of landfill gas contracts with the first of these contracts set to expire in June 2024. (5 TR 430.) 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 is not, however, persuaded that the Company is justified in assuming that, for IRP purposes, none of the contracts will be renewed.

Of greater interest, both witness Jester and Staff witness Harlow include discovery responses showing the Company's current interconnection queue, which identifies up to 570 MW of solar projects that could qualify for a PURPA avoided cost rate and help to defer, displace or partially displace a new facility. The

Company has not yet awarded a contract to any of the 570 MW of projects and has issued communications to renewable generators, stating it has no need for capacity for the next 10 years (5 TR 678) in an attempt to avoid paying qualifying facilities more than the MISO planning reserve auction price for capacity. Witness Jester correctly states:

> DTE's plan to acquire substantial new generation resources while communicating to potential qualifying facility developers that it does not project need for new capacity in the next 10 years runs contrary to the very purpose of PURPA, and undermines the Company's claim that it has analyzed the availability and cost of other electric resource that could defer, displace, or partially (displace) the new facility. The purpose of an integrated resource plan in support of an application for a Certificate of Necessity is to determine the availability and costs of other resources that could defer, displace, or partially displace the proposed facility. (5 TR 432.)

Staff is baffled by the Company's claim that it has no capacity need when it is requesting an 1100 MW CON approval and, as pointed out by witness Lucas, *the Company is projecting up to a 300 MW capacity shortfall in years 2023 through 2028 that could be filled with PURPA Resources.* (5 TR 678.)

Witness Lucas' clearly states that 55% of all market valuation costs associated DTE Electric's Proposed Project are fuel costs that are directly exposed to natural gas price volatility. (5 TR 803.) Solar and wind resources have zero fuel costs and relatively low O&M which can help to hedge gas price volatility. In cross examination, Company witness Bloch agrees that new PURPA contracts help to hedge against gas price volatility. (8 TR 2361.)

Witness Lucas addresses the Company's decision to use 41% capacity credit for solar. He discusses the irregularities in the Company's operation data for Company-owned solar and was able to calculate a higher capacity credit when removing irregularities and notes that the Company's facilities were installed between 2010 and 2013. (5 TR 752.) Taking into account the vast improvements that made in solar panel technologies and installation, Staff agrees with witness Lucas that the capacity credit DTE Electric used in its analysis should have been the MISO default of 50%. In summary, DTE did not robustly addressed its RE portfolio in the IRP.

b. Staff is concerned DTE's proposed load management and demand response is not fulfilling its potential.

Through analysis of the 2017 Statewide Demand Response Potential Study, Staff found the Company to have the potential to offer more demand response programs to customers. (5 TR 260.) On January 12, 2018 Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (MEC-NRDC-SC) and Environmental Law and Policy Center (ELPC) testified in this case highlighting the same demand response concerns as Staff. For the achievable low-level potential shown in the 2017 Statewide Demand Response Potential Study, the Company could achieve an incremental 386 MW of demand response (DR) above their baseline for 2020. (5 TR 422.) Staff notes that the Company's addition of 125 MW as part of its Interruptible Air Conditioning (IAC) program, as modeled in its IRP, is not an increase to its baseline because it is not an increase in participation. Rather the increase is due to the replacement of non-functioning infrastructure—new thermostats. 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 start date for this proposed project and future fossil fuel projects.

The Company stated it has 630 MW of DR in the MISO Capacity auction. (7 TR 2097.) The Company also stated it expects to add an additional 125 MW of capacity by repairing switches for customers currently enrolled in the IAC program, but does not plan to expand the IAC program. (*Id.*) Company witness Kirchner discussed how the Company compared their proposed Demand Side Management to their most recent potential study, completed by GDS Associates in 2016. He stated:

> The Company's proposed DSM programs total 572 MW of existing capacity in 2017 with projected growth of the DSM programs to 697 MW by 2021. The GDS Associates study provided an achievable potential of 845 MW by 2020 in their Smart Thermostats scenario for all available DR programs. The current Demand Side Management plan for the Company is in-line with the suggested achievable potential. (7 TR 2101.)

The Company suggests that even though its DR programs are projected to be lower by 148 MW in 2021 (845 MW – 697 MW) than GDS determined achievable potential, the status quo is somehow sufficient. Staff disagrees. The Company is not adding any new DR programming nor seeking to expand further participation.

Also, the Company is not implementing the dynamic peak pricing programs they have received cost approval to install. The Company has been approved in MPSC Case No. U-18014 to invest in 10,000 thermostats for dynamic peak pricing programs and has failed to implement these thermostats in a timely manner before requesting rate relief for an additional 15,000 thermostats (5 TR 258.)

The Company's analysis has met the bare minimum requirements for this filing by providing the costs of other electric resources that could defer, displace, or partially displace the proposed generation facility. However, Staff recommends that the Commission require that DTE implement the Company's approved DR programs to meet its capacity needs. Staff's review revealed that not only are the Company and customers missing out on cost effective DR potential by not implementing programs and measures that have costs already approved for recovery, but the Company is also not planning to incorporate any additional DR. (5 TR 259.)

Recognizing that the 2017 Statewide Demand Response Potential Study was not available until September 2017, shortly after the application was filed, the results show at least 386 MW of incremental potential in DR for the Company through various programs. MEC-NRDC-SC Witness Jester stated that the Commission's 2017 study is more recent and covers a broader range of demand response programs than the GDS study on which DTE Energy relies. (5 TR 421.) He also showed that the Company has more program options than what was analyzed in the Company's filing. (5 TR 423.)

DR in combination with EWR and RE, as a triad, could be more cost-effective to displace or delay building a generation facility. Staff recommends that the Commission require the Company to engage in much more robust modeling for future IRP filings that incorporates more DR programs, not only as a stand-alone resource but as a resource package including EWR and RE.

c. Staff is concerned with DTE's proposed bare bones EWR program.

In its application, the Company modeled EWR program offerings at the 2.0%, 1.5%, 1.0%, and <1.0% levels. According to the Michigan Lower Peninsula Energy Efficiency Potential Study, completed in August of 2017 by GDS Associates, the Company could cost effectively achieve savings levels equal to 2% or more through 2026, and possibly longer. (5 TR 245.) The Company did not give valid reasons to keep the EWR levels at 1.5% other than they were not aware of the new achievable levels at the time of the application was submitted. (5 TR 249.) Although the stated 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. The Company was involved with the development of the revised potential study, because the same contractor GDS Associates, developed the utility specific potential study from 2016, and the combined potential study from 2017 and was active in the energy waste reduction potential study workgroup for 7 months.

The Company was well-aware of the findings prior to the study being issued, and prior to the application filing. Staff does not agree with the Company position that the outcomes of this combined potential study are irrelevant. (7 TR 2047.) The findings are, in fact, made even more significant because they are the most current assessment of potential. During the pendency of this case, it would not have been difficult for the Company to adjust its EWR targets for this CON request, and Staff recommends that the Commission take into account the Company's failure to do so. The Company expressed concern that ramping up in earlier years, and then, possibly, ramping down in future years would be burdensome. (7 TR 2050.)

In rebuttal testimony Company witness Bilyeu questions Staff witness Gould's recommendation to require a 2% annual savings target as a condition of the certificate. He states:

> Q. On pages 14 and 15 of her testimony, Staff Witness Gould recommends that the Company implement the 2% savings scenario for 2019-2020 as a condition to receiving the Certificate of Necessity. Does the Company believe this is appropriate?
>
> A. No. This proposal 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 that, per PA 342." (7 TR 2051)

The Company is incorrect in this response. First, the Company has already demonstrated in their amended 2017 EWR plan in MPSC Case No. U-17762 that it can achieve the 1.5% scenario, but that does not prove that the Company would be unable to achieve the 2% scenario. Second, the fact that Company has already planned to achieve 1.5% for 2018 and 2019 provides no compelling reason to not increase that plan to 2% annually. EWR plan amendments are administratively efficient and completed within 90 days of amendment filing, and the Company EWR plan can be quickly revised. Finally, the fact that Company will file another IRP by March 29 is not a reason to refuse to implement 2% programming levels now. None of the Company's responses are valid reasons to avoid implementing the 2% programming levels. DTE's arguments, at base, are that DTE's witnesses elect to achieve 1.5% programming levels because they say so, which is neither clear nor convincing.

While there may be additional work and costs associated with ramping up a program, that additional work and cost is associated with cost effective savings for the Company and their customers. (7 TR 2017.) The Company's customers also benefit in many monetary and non-monetary ways from the increased EWR savings. Witness Gould testified that increased work load is not a reasonable excuse to not implement all cost effective and achievable EWR for the citizens and businesses of Michigan.

Witness Gould does not believe the idea of offering programs at a 2% level annually through 2021 and beyond would be considered inconsistent. (5 TR 247.) If the Company for some reason was unable to maintain programming at a level of 2%, and was forced to lower their achievement levels to 1.75% or 1.5% at that time, it does not seem logical to consider that to be inconsistent programming behavior.

The Company knows firsthand how to ramp up a program. It was able to ramp up programming from 2009 through 2012 under PA 295. The Company also ramped up from 1.15% to 1.5% for program years 2017, in Case No U-17762, in order to earn the new increased incentive payment authorized in PA 342. They were able to do this without adding any additional funding to their program portfolio. (5 TR 251). To increase another 0.5% from 2018 through 2021 and beyond is not only feasible, it is reasonable and prudent. While Staff recommends approval of the CON requests, there is ample evidence in the record for the Commission to require alternatives, such as increased EWR to defer the need for a plant.

Given recent Commission-issued guidance, the Company inadequately assessed EWR, which resulted in lower amounts of EWR recommended for the purposes of this CON. EWR was not optimally accounted for because the Company selected the potential for EWR to be at the 1.5% annual savings level which DTE, according to its 2016 potential study, believes is adequate. Staff believes the Company chose its level of EWR to meet the criteria to earn the maximum financial incentive payment, and then built its energy and capacity needs on top of this. (5 TR 247)

Higher EWR levels produce not only greater savings for DTE customers, but also increased reliability in meeting DTE's energy and capacity needs. Witness Gould recommends the Company implement EWR at the 2% savings level for these reasons and for the added benefits their customers will realize, such as added comfort and safety in their homes, lower energy bills and a cleaner environment. (5 TR 244.) The 2% EWR annual savings level is still highly cost effective.

In Company witness Bilyeu's rebuttal testimony, he disagrees that the Michigan Lower Peninsula Electric EE Potential study was cost effective. He states:

> Q. Is the 100% incentive scenario included in the Michigan Lower Peninsula Electric Energy Efficiency Potential study and recommended by Witness Gould economically justified?
>
> A. No. The Michigan Lower Peninsula Electric Energy Efficiency Potential study included a scenario that increased incentive levels to 100% of measure incremental cost. As detailed in Witness Gould's Exhibit KMG-2, increasing incentive levels to 100% only slightly increased savings through 2036 from 20.4% to 23.8%. Further, this 100% incentive scenario concluded that increasing incentive levels has an exponential impact on the required portfolio budget, and produced annual program budgets that were on average about 50% higher than the base case potential study analysis. (7 TR 2049)

Staff agrees that increasing the incentive levels to 100% would increase the budget for EWR, but, if the programs are still cost-effective, then energy waste reduction provides the least cost option for energy supply for their customers. EWR also provides many non-monetary benefits that fossil fueled power plant supply cannot offer, as stated above. What Company witness Bilyeu also leaves out is that Staff 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. EWR and the subsequent incentive level offerings is not an all or nothing proposition.

Witness Bilyeu further claims in his rebuttal that witness Gould's characterization of the Company proposed target of 1.5% annual energy waste reduction savings is misleading. He states:

> Q. Witness Gould's statement on page 9, lines 13-16 of her testimony that the Company is proposing to achieve an energy savings level of 1.5%, which allows them to reach the legislative requirement, and meet base eligibility for the maximum incentive payment allowed by the Act" (is) misleading?
>
> A. This statement is misleading as it implies the Company's plan will simply reach the legislative requirement, when in fact, the Company's plan exceeds the legislative requirement by 50%. (7 TR 2049.)

Witness Gould's statement is not misleading. (5 TR 247.) Witness Gould states, "...the Company is proposing to achieve an energy savings level of 1.5%, which allows them to reach the legislative requirement, and *meet base eligibility* for the maximum incentive payment allowed by the Act." (Emphasis added.) Witness Gould emphasizes that the Company's targets will meet not only the Legislative requirement, but also meet the minimum eligibility for the maximum incentive payment allowed, but nothing more. It is apparent the Company set this goal specifically to meet the Legislative requirement for EWR, irrespective of the CON requests, and subsequently exceed it just enough to reach the maximum financial incentive payment allowed. Essentially, the Company's goal reflects the least amount of effort for the maximum return without an effort to attempt to defer or displace the need to build a nearly one billion dollar plant.

Since the Company amended its 2017 EWR plan to reach a target of 1.5%, that savings level appears to have been pre-decided and then subtracted from the

Company's load forecast rather than modeled as a supply side resource. The EWR modeling was done in a manner to minimize the contribution of EWR for this certificate of need application. Multiple intervenors testified to the lack of robust EWR modelling efforts made by the Company. Specifically, the testimony of George Evans on behalf of MEC-NRDC-SC, was compelling, and confirms Staff's opinion of the Company's EWR deficiencies. (5 TR 331.)

DTE's application for a CON for approval of an 1100 MW natural gas combined cycle gas plant does not account for the benefits of adding additional EWR, DR, and renewable energy to meet or supplement the Company's energy load requirements. This resource triad, joined, can delay or displace the need for a new natural gas combined cycle generating facility. This triad can, at the very least, provide enough energy and capacity to decrease the size of a new generating facility. And, this triad when optimally and adequately modeled can provide a cleaner environment for Michigan, greater savings for utility paying customers, reduced risk exposure to natural gas fuel prices, and healthier homes and businesses in Michigan. As stated by witness Proudfoot, although, Staff recommends in general that the 1100 MW plant could be approved in this matter, there exist sufficient deficiencies in the IRP for the Commission to justify another approach.

4. The IRP minimally analyzed alternatives that could defer, displace, or partially displace the proposed generation facility.

The Company provided some analysis of alternative resources such as energy efficiency (EE) and demand response (DR) as part of its IRP process. (5 TR 214.)

MCL 460.6s(11)(f) does not detail the extent of the analysis that should be performed, therefore, leaving that determination to the Commission. And, while the Company was aware of the process to determine the parameters, it was not able to rely on the recently adopted Statewide IRP Model Parameters. (11/21/2017 Order, MPSC Case No. U-18418.

In light of the current guidance, Staff and Intervenors have identified significant shortfalls in the Company's analysis of demand response, energy efficiency and renewable energy including PURPA. "The Company has not modeled energy efficiency and demand response to the achievable and cost-effective amounts reported in the potential studies. (5 TR 214; State of Michigan Demand Response Potential Study[2], Michigan Lower Peninsula Electric Energy Efficiency Potential Study[3].) Staff expressed definite concerns with the Company's scenario development because "the Company did not model these resources simultaneously, at the amounts that Staff believes to be achievable and cost-effective, therefore Staff has no way of knowing if this type of multi-resource approach would be more cost-effective for the rate-payer than the Company's proposed project." (5 TR 214.) MEC-NRDC-SC agree with Staff's concerns. (5 TR 347.) MEC-NRDC-SC identified similar defects with the Company's analysis, specifically the failure to allow additional demand response resources to be selected prior to 2023, flaws in energy

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[2]http://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf

[3]http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf, August 11, 2017.

efficiency program modeling, incorrect capacity factors for solar and flaws in modeling renewable resources. (5 TR 329-330.)

ELPC presented an alternative scenario that included increased renewable, demand response and energy efficiency that, according to ELPC's calculations, has a lower NPV cost. (5 TR 901.) Likewise, Staff made a request of the Company to run a Staff scenario that included increased renewable resources, energy efficiency, and demand response resources. The Company's response, declining Staff's request, received on December 1 2017, is in evidence as Staff Exhibit 1.10.

Next, MEC-NRDC-SC provided rebuttal testimony on February 2, 2018 targeted at addressing Staff's request to DTE regarding Staff's proposed dynamic scenario. MEC-NRDC-SC's presentation illustrates a significant savings and deferral of the proposed project. (5 TR 557.)

Simultaneously, DTE presented in rebuttal a scenario run attempting to represent the result of Staff's scenario request in its rebuttal testimony on February 2, 2017. The Company provides evidence that it claims is a "proxy for the Staff scenario." (7 TR 1815.) The Company also notes a flaw in one of the many scenario cases run by MEC-NRDC-SC, but did not comment on the remaining scenario cases. (*Id.*) The Company's failure to provide the run-in discovery goes to the lack of weight that should be given to the evidence.

Unfortunately, with the late presentations of alternative modeling scenarios made by both intervening parties and the Company, as well as the defects noted by each party about the other's analysis, Staff did not have adequate time to fully analyze all the parties' scenarios to determine the accuracy of the various modeling outputs. Thus, Staff cannot say conclusively which scenario is the most appropriate. The complexity and technical nature of IRP modeling does not lend itself to spur-of-the-moment analysis. In part, this may have been the result of the reluctance of the Company to provide timely and full responses to discovery. For instance, to obtain modeling options, the Intervenors were faced with filing a motion to compel with Staff's concurrence. And, Staff was not able to review bid information simply by requesting it in discovery, pursuant to a protective order. Instead, that matter went to hearing and order for DTE to provide the information. Still, despite these stumbling blocks, "[i]n general, the Company explored many scenarios that provide insight into the resource requirements for a variety of future conditions." (5 TR 208.)

Absent the guidance now available through the Statewide Modeling Parameter Setting adopted by the Commission in its 11/21/2017 Order. (Attachment A.) Staff finds that the Company met the minimum standard for analyzing alternative resources that could differ, displace, or partially displace the proposed project but expects that the Company would perform a more robust analysis when faced with filing an IRP under the newly adopted guidance.

5. The IRP analyzed DTE's transmission options.

The Company analyzed transmission alternatives that included the current ITC transmission grid and import limits within the context of the MISO capacity construct. The analysis included the ability to deliver firm transmission supply to meet demand, existing interconnecting tie lines, the effects of DTE coal-fired retirements, and near and long-term transmission expansion plans as indicated through the MISO Transmission Expansion Planning (MTEP) process. (5 TR 216.) The MTEP process is a process to ensure the reliable operation of the transmission system that would not necessarily indicate market or economic related options that might enable resources from outside of the MISO Local Resource Zone 7. (*Id.*)

MEC-NRDC-SC discuss transmission options both within the MISO region and outside of the MISO region in neighboring PJM and Independent Electric System Operator (IESO) regions with which Michigan has ties. The Company argues there are more stringent import limits that exist for Zone 7 due to the MISO construct that includes both a Planning Reserve Margin Requirement (PRMR) and a Local Clearing Requirement (LCR). (7 TR 2243.) The resulting Effective Capacity Import Limit (ECIL) restricts the amount of imports allowed to be used for capacity into MISO Zone 7 below the Capacity Import Limit (CIL) and the total of Zone 7 ECIL has to be shared amongst all load serving entities in the zone. 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.)

The Company admits that to the extent that resources in IESO chose to comply with the MISO rules, that capacity from Ontario could be counted toward meeting the Zone 7 LCR requirement. (7 TR 2264.) Additionally, the Company's

Exhibit A-63 does include allowing the IESO to become qualified as an external resource as a priority for the 2019-2020 planning year. (*Id.*) This coupled with the decreased Staff projected shortage may allow for options that the Company assumed in its IRP were not available.

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 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 also understands that the transmission landscape is ever changing. If the Commission holds that the Company has provided an adequate analysis to determine that it needs the proposed project, as a best alternative, Staff recommends that the Commission specify that the analysis may not be adequate in future IRP cases, given unknown future changes to the transmission system, the MISO construct, and available qualified resources located outside of the MISO region.

D. In sum, Staff supports the approval of DTE's 3 requests for Certificates of Public Convenience and Necessity (minus excess contingency) and the proposed accounting treatment of construction costs.

1. The Commission should approve DTE's application, recognizing the need for robust analysis in the upcoming IRP.

In light of the above, within the context of the guidance available at the time the application was filed, the Company demonstrated that the 1100 MW of power that will be supplied from its proposed construction is needed. (5 TR 181.) The application should be approved, as filed, with the requirement that DTE file a robust IRP in compliance with the subsequent guidance issued by the Commission in its November 21 and December 20, 2017 Orders. DTE should not be in the same position in 2029 when it projects it may be in need of another CON filing.

2. Staff also supports the Company's proposed accounting and ratemaking treatment of its construction financing costs.

Staff supports the Company's proposed accounting and ratemaking treatment of its construction financing costs, as conforming to the Act. PA 341 of 2016, MCL 460.6s (12) states in full:

> 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 allowed to recognize, accrue, and defer the allowance for funds used during construction.

Company witness Uzenski testified that DTE is requesting current recovery of financing costs on this project, stating that "in a general rate case, the costs of construction work in progress for the proposed project, reflected in the projected test year, would be included in rate base without an AFUDC offset." (5 TR 1498.) She went on to say that "[c]onstruction costs not included in rate base (due to regulatory lag) will accrue AFUDC until they are reflected in rate base." (*Id.*) Ms. Uzenski additionally stated:

> It is my understanding that PA 341 is intended to ensure Michigan's future capacity requirements are met. I further understand that the new statute allows the Commission to approve the recovery of financing costs on construction work in progress for projects undertaken to help meet those requirements. However, DTE Electric reserves the right to use traditional accounting and ratemaking treatment of financing costs incurred during the CON construction period should the Commission not approve the requested accounting and ratemaking treatment of financing costs. (5 TR 1498-1499.)

Staff witness Nichols agreed with Company witness Uzenski that Staff supports "current recovery of financing costs related to the proposed project as long as the project costs are requested in a general rate case as part of base rates and the costs are found to be reasonable and prudent." (6 TR 1579.) Nichols stated that the Company requested current recovery of financing costs in its current electric base rate MPSC Case No. U-18255, but, in that case, Staff witness Simpson recommended disallowance of those costs at this time, as the filing of the costs was premature. (6 TR 1579-1580.) Witness Nichols testified in agreement with the Company, that "[i]f the Commission does not approve the accounting request for current recovery of financing costs on the proposed project, Staff supports traditional accounting and ratemaking treatment of financing costs incurred during the CON construction period." (5 TR 1580.)

Therefore, Staff recommends to the Commission that current recovery of financing costs related to the proposed project should be approved if the project costs are requested in a general rate case as part of base rates and the costs are found to be reasonable and prudent. Additionally, Staff recommends that if the Commission does not approve the accounting request for current recovery of financing costs on the proposed project, traditional accounting and ratemaking treatment of financing costs incurred during the CON construction period is appropriate.

E. Staff recommends approving the CON with no more than a $17.8 million contingency.

The Company included $55 million in contingency costs in the estimate for the proposed project as shown in Exhibit A-43. Staff recommended that $37.2 million of proposed contingency costs be removed. This adjustment provides a contingency balance of $17.8 million for the proposed project. (5 TR 205.) The Company has argued that $55 million is an appropriate contingency amount because it represents 6% of the total project cost. (8 TR 2611.) Subject to approval of the Company's CON application, this project is expected to be built as a *full-wrap* EPC project with a *fixed-price* contract with a remaining $55 million in expected owners' costs. Given the fixed price contract nature for the bulk of the capital expenditures for the proposed project, Staff believes that there should be very little contingency needed.

According to MCL 460.6s, subsection 4(c), as reflected in its application, the Company was statutorily allowed to update its costs up to 150 days after its initial filing. In fact, *three* Company's witnesses identified that it intended to do so in testimony. (6 TR 1623; 6 TR 1769; 8 TR 2611.) The Company ultimately chose not to provide a cost update on or before the 150-day timeframe in this case. If the Company had identified changes that raised the project cost, such as additional scope, etc., it could have provided a cost update to the case to allow for proper discovery of any new or changed costs identified.

Staff's position that very little contingency is needed for this project is supported by the fact that the Company has not provided a 150-day cost update. If the project does require capital expenditures beyond the Company's estimates provided in this case, the Commission may include those additional costs in rates "if it finds by a preponderance of evidence that the additional costs were prudently incurred." MCL 460.6s(9). Therefore, Staff recommends the Company's contingency allowance in this case be reduced to $17.8 million.

F. The Company had adequate interconnection infrastructure and transmission interconnection.

1. The Company provided information that it has reasonable gas interconnection infrastructure.

The proposed project is in close proximity to existing natural gas infrastructure. (8 TR 2554.) Three existing large natural gas transmission pipelines run approximately one mile north of the proposed site. The lateral line needed for the proposed project is estimated to be three miles in length subject to design variations. (8 TR 2576). Bid solicitation from nearby service providers for natural gas transportation and storage services and to enter into a firm gas transportation agreement has begun. (8 TR 2575-2576.)

The Company is simultaneously soliciting for two aspects of gas transmission. First, the Company is soliciting to construct a new lateral line, gas compression, and interconnection facilities. (8 TR 2555.) The Company has provided cost estimates for the construction of the lateral line and gas compression in confidential Exhibit A-68. Second, DTE is seeking a firm gas transportation agreement that includes storage. The estimated cost for transportation and storage is part of the Company's natural gas delivered cost forecast in A-30 as stated in Staff Exhibit S-6. The Company has not determined if it anticipates needing to file an Act 9 application for the construction of the lateral natural gas pipeline and no such approval is being sought in this case.

2. The Company provided information regarding the adequacy of electric transmission interconnection.

The Company's identified proposed project site is favorably near existing electric transmission lines. (8 TR 2605.) The Company estimates the transmission network upgrade costs to be $29.3 million and anticipates the costs to be refunded as allowed under Attachment FF Section II. A. 2. D. 4 of the MISO tariff. As stated in Exhibit S-1.5, the Company has not included the estimated transmission costs in the cost estimate for this project. The estimates provided by the Company were not provided by International Transmission Company (ITC), the transmission owner at the proposed site. The Company consultant NDV prepared the Company's transmission network upgrade estimates. The Company has indicated only transmission network upgrade costs related to 120 kV transmission or higher in this case. The Company has not identified nor is seeking approval for any upgrade costs to the distribution network, 100 kV or lower, in this case. (7 TR 2213-2214.)

VI. Conclusion and Request for Relief

In conclusion, Staff recommends approval of the three requests for CON. Staff submits that there are enough defects in the underlying IRP, as identified by Staff and Intervenor witnesses, that the Commission could choose to make another decision, such as requiring the Company to refile its application or build a smaller plant. The Company will be filing another IRP in accordance with PA 341 and the Commission's order in U-18461, which requests that DTE file its IRP on March 29, 2019 (or earlier, upon request, and spaced within 21 days from other IRP filings.) Staff requests that the Commission explicitly require the DTE to develop a robust IRP in accordance with that statute for its next filing.

The Company's next IRP must meet the new IRP filing requirements contained in the 2017 Order in U-15896, which the current IRP does not adhere to. (Attachment B.) Further, although not all resources require a CON, the IRP can potentially approve investment for the development of smaller resources per MCL 460.6t(12) that have been identified by Staff and Intervenors in this case. These alternative resources take time to develop.

Staff understands the Company wishes to take a measured approach to alternative resources, cognizant of the importance of reliability, as it proceeds.

Staff expects that the Company's next IRP to be filed in March of 2019 will include the development of these resources to meet cost effective potentials as identified in the potential studies for EE and DR. The EE and DR potential studies which should be used are not the utility studies but rather the statewide assessments, which provided more aggressive results.

A steady application to meeting this goal will increase the likelihood that, the other resources taken as a whole, defer or displace the need for DTE's projected second 2029 NGCC. This is what the Legislature intended when it enacted Act 341 of 2016. It is also what the Commission intended in carefully crafting guidance in response to the Act, and that intent should not be thwarted. Staff recommends, therefore, that the Commission adopt its recommendations and grant the three requested CONs with the specification that this case should not be a model for future IRP filings, as fully articulated above.

Respectfully submitted,

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

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Dated: March 2, 2018
18419/Initial Brief

Attachment A

S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion to implement the provisions of Section 6t(1) of 2016 PA 341.	))))	Case No. U-18418

At the November 21, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

ORDER

History of Proceedings

On December 21, 2016, Governor Rick Snyder signed into law Public Act 341 of 2016 (Act 341), which amended Public Act 3 of 1939 and became effective on April 20, 2017. Act 341 updated Michigan's energy laws related to utility rate cases, customer choice, certificate of necessity, electric capacity resource adequacy, and established an integrated resource planning (IRP) process. The IRP provisions are an important component of the new energy law, which is expected to increase affordability for customers, improve the reliability of electricity, and help protect the environment. Utilities use IRPs to identify and evaluate options for meeting long-term electricity needs over a specified time period. Modeling tools are used to help evaluate a combination of supply-side and demand-side resources under different scenarios and assumptions related to load growth, fuel prices, emissions, and other variables.

Act 341 establishes a new IRP framework for electric utilities whose rates are regulated by the Commission. Specifically, Section 6t(1) of Act 341 requires the Commission, with input from the Michigan Agency for Energy (MAE), the Michigan Department of Environmental Quality (MDEQ), and other interested parties, to commence a proceeding to establish parameters related to the IRP process.

As part of the proceeding, the Commission must assess the potential for both demand response (DR) and EWR (EWR), take an inventory of existing or proposed environmental requirements affecting electric utilities, identify key inputs such as planning reserve margin levels, and establish modeling scenarios and assumptions to be used by each utility in filing company-specific IRP cases under Section 6t(3) of Act 341. The Commission must also provide opportunities for input from other state agencies and the public. Specifically, the Commission must accomplish the following:

> (a) Conduct an assessment of the potential for EWR in this state, based on what is economically feasible, as well as what is reasonably achievable.
>
> (b) Conduct an assessment for the use of demand response programs in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already been installed in this state and seek to fully maximize potential benefits to ratepayers in lowering utility bills.
>
> (c) Identify significant state or federal environmental regulations, laws, or rules and how each regulation, law, or rule would affect electric utilities in this state.
>
> (d) Identify any formally proposed state or federal environmental regulation, law, or rule that has been published in the Michigan Register or the Federal Register and how the proposed regulation, law, or rule would affect electric utilities in this state.
>
> (e) Identify any required planning reserve margins and local clearing requirements in areas of this state.
>
> (f) Establish modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its

integrated resource plan filed under subsection (3), including, but not limited to, all of the following:

(i) Any required planning reserve margin and local clearing requirements.

(ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.

(iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected EWR savings, and projected load management and demand response savings.

(iv) Any regional infrastructure limitations in this state.

(v) The projected cost of different types of fuel used for electric generation.

(g) Allow other state agencies to provide input regarding any other regulatory requirements that should be included in modeling scenarios and assumptions.

(h) Publish a copy of the proposed modeling scenarios and assumptions to be used in the integrated resource plans on the commission's website.

(i) Before issuing the final modeling scenarios and assumptions each electric utility should include in developing its integrated resource plan, receive written comments and hold hearings to solicit public input regarding the proposed modeling scenarios and assumptions.

MCL 460.6t(1).

On March 10, 2017, the Commission Staff (Staff), MAE and MDEQ initiated a collaborative process with stakeholders to address the requirements of Section 6t(1). Subsequently, the Staff held 11 stakeholder meetings that led to the development of the Draft Integrated Resource Planning Parameters (Strawman Proposal). In accordance with MCL 460.6t(1), the Strawman Proposal contains proposed modeling scenarios, along with multiple assumptions or sensitivity analyses (sensitivities) related to load growth or other variables for each scenario, which, if approved, would have to be modeled by utilities in their individual IRP applications along with any additional modeling scenarios identified by the utility.

To allow the Commission to consider the Strawman Proposal and seek additional feedback on its contents as part of the instant proceeding, on July 31, 2017, the Commission issued its Order, Notice of Public Hearing, and Opportunity to Comment (July 31 order) directing the Staff to file the final version of the Strawman Proposal in this docket by August 31, 2017, with a copy posted on the Commission's website. The final Strawman Proposal was filed in this docket as directed.

In order to provide interested persons the opportunity for input on the final version of Strawman Proposal and the overall IRP process, the July 31 order also provided the opportunity for any person to submit written or electronic comments with the Commission. Initial comments were due by October 6, 2017, and reply comments due by October 20, 2017. The July 31 order further provided for three public hearings, which were held in Livonia on September 6, 2017, Grand Rapids on September 13, 2017, and Marquette on September 19, 2017. Transcribed comments on the IRP parameters from each of the three hearings were also filed in the docket. A summary of the all of the comments received pursuant to the July 31 order is provided below. The Commission values this feedback as an integral part of the IRP process and implementing the enacted legislation.

In addition to the comments received pursuant to the July 31 order, on October 5, 2017 (October 5 notice), the Commission issued a notice of opportunity to comment to interested parties following the completion of the Michigan Demand Response Potential Study (DR Study). MCL 460.6t(1) requires, as part of the IRP planning process, the Commission to "[c]onduct an assessment for the use of demand response programs in this state, based on what is technologically feasible, as well as what is reasonably achievable." MCL 460.6t(1)(b). The DR Study was filed in this docket on October 2, 2017. Initial comments specifically addressing the DR Study in relation to the Strawman Proposal were due by October 13, 2017, with reply comments due by October 27,

2017. The comments received pursuant to the October 5 notice are addressed as part of the discussion of the DR provisions of the Strawman Proposal.

Pursuant to Section 6t(2), this proceeding is not treated as a contested case proceeding. The Commission's decisions in this proceeding are not appealable until a final order is issued in an individual utility IRP proceeding. The results will be incorporated into the individual utility IRP filings in 2018 and 2019 under the schedule set forth in Case No. U-18461.

Initial Comments

Union of Concerned Scientists

The Union of Concerned Scientists (UCS) comments that a comprehensive understanding of the costs, benefits, risks, and potential impacts of utility resource plans is critical. UCS believes that important improvements should be incorporated into the final document to ensure a successful, comprehensive IRP process that will ultimately to protect ratepayers. The following is a list of the UCS's suggested improvements:

1. The Michigan Environmental Protection Act should be included in the list of applicable state and federal laws;
2. Language describing scenarios and sensitivities should be standardized and avoid using subjective qualifiers;
3. Scenario and sensitivity descriptions should include rates of change associated with changes to input assumptions;
4. Treatment of generic new resources should be clarified;
5. The environmental policy scenario should specify whether the 30% reduction in carbon emissions (and 50% reduction sensitivity) is through a hard cap on emissions or a price on carbon; and
6. The IRP parameters document should address how utilities must evaluate and/or rank the scenarios and sensitivities.

The UCS also provides suggested input assumptions. First, the UCS comments that the analysis period and evaluation of potential plans and their impacts should be conducted at five-year intervals as specified, but the full analysis period should extend to at least 20 years due to the long-term nature of utility investments and per common utility and electricity sector practices. Second, the UCS comments that the utility model regions should adequately represent Canadian provinces that are connected to the filing utility's service territory to adequately represent the flow of energy across utility territory borders. And third, the UCS comments that capacity factors for RE resources must be evaluated on a geographic and temporal granularity that allows for a true evaluation of the potential for these resources to meet energy, capacity, and ancillary service needs. This must be more granular than statewide and annual averages and should be specific to multiple zones across the model region if data are available.

The UCS further comments that consideration of the environmental impacts and risk elements of a utility plan are critical and distinct elements to robust resource planning. The UCS provides that the Commission should specifically require a full accounting of emissions of carbon dioxide and other greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants, as well as the projected production of wastewater effluent, coal combustion residues, and other byproducts of electricity production that have the potential to impact public health and the environment over the planning period. According to the UCS, emissions should be reported annually throughout the planning period for utility operations as well as contractual arrangements with merchant generators that will be supplying energy to meet the utility's expected demand.

The Commission agrees that the long-term nature of utility investments warrants an analysis period longer than 15 years, and also agrees that the model region should adequately represent the flow of energy across utility territory borders. Section IX of Exhibit A has been updated to address these suggested revisions.

The UCS, along with several other commenters, suggested that the Michigan Environmental Protection Act (MEPA) should be included in the list of applicable state and federal laws. The Commission acknowledges that MEPA is among the environmental laws that could affect the power generation sector and, therefore, has included it in the list of environmental laws as required by Section 6t of PA 341. The Commission notes, however, that an IRP proceeding is distinctly different from licensing or siting proceedings that authorize the construction of new facilities with attendant consideration of environmental impairment and mitigating measures pursuant to MEPA. The Commission's approval of an IRP does not authorize construction of a new facility nor is an approved IRP required to construct a new facility. Further, review and approval of an electric utility's IRP by the Commission does not constitute a finding of actual compliance with applicable state and federal environmental laws. Electric utilities that construct and operate a facility included in an approved integrated resource plan remain responsible for complying with all applicable state and federal environmental laws, including Part 31 and Part 55 of the Natural Resources and Environmental Protection Act.

Several commenters, including the UCS, sought clarification regarding whether specified carbon reductions should be achieved through a hard cap on emissions or a price on carbon. The Commission clarifies in Exhibit A that specified carbon reductions should be achieved, in any of the required scenarios and sensitivities, through a hard cap on emissions. The Commission has also attempted to address several of the general comments made by the UCS in the revised attachment including standardizing language and using rates of change in descriptions.

The Commission appreciates the UCS's comments regarding the treatment of new resources, the evaluation of risk, and the treatment of environmental benefits. The Commission expects the utilities to fully document the treatment of new resources, the evaluation of risk, and the treatment of environmental benefits in IRP filings, but the Commission is not persuaded that specific requirements addressing those issues should be added to the Michigan IRP Parameters (Exhibit A) at this time.

With respect to comments on RE capacity factors, the Commission notes Section X includes a requirement to consider technology improvements and geographic location, and Section IX includes a specification for RE capacity factors to include a justification from the utility for utility-specific capacity factors. The Commission expects that parties wishing to challenge the capacity factors will do so as part of a contested case.

Indiana Michigan Power Company

Indiana Michigan Power Company (I&M) concurs with and accepts the draft recommendation relative to the multistate provisions offered by the Staff in its draft proposal. The company appreciates that the Staff has recognized the unique planning-related circumstances faced by multistate integrated utilities, such as I&M.

Michigan Department of Environmental Quality

The MDEQ submitted a proposed regulatory timeline chart to help satisfy requirements of Section 6t(1)(c) of Act 341. The MDEQ proposes that the charted timeline be included with the final IRP document.

The Commission agrees, and the regulatory timeline chart has been included.

Upper Peninsula Association of County Commissioners and Upper Peninsula Commission for Area Progress

The Upper Peninsula Association of County Commissioners (UPACC) and Upper Peninsula Commission for Area Progress (UPCAP) strongly urge that the Upper Peninsula (UP) IRPs include: (1) incentives for energy waste reduction (EWR) to reduce costs today and into the future; and (2) analysis regarding how incremental investments would compare to large investments in specific technologies that might be obsolete in a few years.

UPACC and UPCAP further comment that modular, distributed investments are likely to be the most prudent choice for the UP instead of large, capital intensive investments that take decades to pay for. UPACC and UPCAP are most interested in strategic investments in local and regional energy infrastructure that stimulate jobs. As resources are re-allocated in the future, equitable transition for the employees should be required in IRPs.

The Commission agrees that EWR should be evaluated in the utility IRPs and notes three required scenarios each include a sensitivity evaluating aggressive levels of EWR. The Commission addressed UPACC's and UPCAP's comment regarding an analysis of incremental investments compared to large investments in section X of Exhibit A.

Michigan Biomass

Michigan Biomass comments that biomass facilities have, over the long term, demonstrated their reliability with high availability and capacity factors, all at the full and actual avoided cost of the utility. Michigan Biomass provides that its members are specifically interested in how the IRP and related decision-making processes will value the biomass ancillary services, which contribute to a diverse, "no regrets" energy future for this state. Michigan Biomass comments that biomass power plants provide the same reliable generation as utilities and other sources, but also bring additional value to ratepayers through their ancillary services such as: (1) critical grid support in rural areas of the state that includes voltage stabilization, volt-amperes reactive, and reduced need for transmission and its related costs and line losses; (2) a market for timber harvest and forest management residuals that would not otherwise exist, which contributes to sustainable forestry and health and product forest resources; and (3) environmentally responsible, cost-effective management of waste materials, including $7.5 million in scrap tire disposal alone.

Michigan Biomass comments that the value of these ancillary services are best captured in the IRP process in Scenario 1: Business as Usual (BAU). Scenario 1, according to Michigan Biomass, must presume no changes to the Public Utility Regulatory Policy Act (PURPA) or a utility's obligations under that law. Michigan Biomass further adds that three of its member facilities have PURPA-required power purchase agreements (PPAs) with Consumers Energy Company (Consumers) that extend beyond 2026 and, therefore, must figure into the appropriate timeframe in Consumers' modeling under this scenario. Additionally, Michigan Biomass also represents three small qualifying facilities of 20 mega-watts (MW) and under in size. Michigan Biomass comments that under Sec. 210 of the PURPA statute, Michigan regulated utilities are obligated to buy energy and capacity from these small qualified facilities (QFs) even though the initial terms of their PPAs may expire during one of the BAU timeframes. Therefore, Michigan Biomass continues, utility IRPs under the BAU scenario must include small QF generation currently under contract in all timeframes, regardless of when the initial terms of that contract may expire.

Michigan Biomass further comments that these steps will help to preserve biomass power generation in Michigan that will figure prominently into Scenario 3: Environmental Policy, particularly as it relates to carbon constraints. Michigan Biomass adds that the United States Environmental Protection Agency (EPA) has determined biomass power to be carbon neutral when generated from wood residuals and byproducts, as is the case in Michigan. Michigan Biomass comments that keeping today's biomass power generators viable ensures they will be around to make their contributions to Michigan's energy portfolio in a carbon-constrained world.

The Commission agrees that presuming no changes to PURPA or a utility's obligations under that law is reasonable, and has so reflected by adding the assumption that existing PURPA contracts would be renewed to three required scenarios in Exhibit A.

Michigan Energy Efficiency Contractors Association

The Michigan Energy Efficiency Contractors Association (MEECA) encourages the Commission to include as part of the IRP process the following recommendations from the Lawrence Berkeley National Laboratory (LBNL) made during the August 2017 IRP Stakeholder Group presentation:

1. Identify best practices for establishing the time-varying value of energy efficiency (EE) in integrated resource planning and demand-side management planning to ensure investment in a least-cost, reliable electric system;

2. Establish protocols for consistent methods and procedures for developing end-use load shapes and load shapes of efficiency measures; and

3. Establish common methods for assessing the time-varying value of energy savings, including values that are often missing such as deferred or avoided transmission and distribution investments.

MEECA further comments that the economic impacts of EWR help achieve the Legislature's objective to increase Michigan jobs as stated in Section 8 of Act 341. MEECA also comments that representing EWR resource at the program-level in the IRP modeling, not the measure-level performance, would better illustrate the value of EWR programs that utilize longer-lived efficiency measures and achieve deeper energy savings. Additionally, MEECA comments that any EWR financial incentives allowed under Act 341 should be only be approved for schemes that that would drive exceptional performance beyond EWR targets. Finally, MEECA comments that in light of the risk and uncertainty inherent in utility resource planning, it is critical that the limitations of IRP modeling be taken into account when making large utility investment decisions.

The Commission appreciates MEECA's comments and notes that the revised Exhibit A includes baseline EWR assumptions at a level where the utility is able to maximize its allowable financial incentive under the law, and has included aggressive levels of EWR, ramping up 2.5% annually, to be evaluated through sensitivity analysis. The Commission also appreciates MEECA's comments regarding the recommendations from the LBNL presentation, and the Commission intends to continue researching and pursuing best practices for modeling EWR, DR, and their respective impact on load shapes. While the Commission finds MEECA's comment regarding modeling EWR at the program level to be a worthy goal, the Commission notes that the sheer number of different potential EWR programs that could be modeled is substantial. Without additional specificity regarding some parameters surrounding which or how many individual programs to model, the Commission declines to add a specific requirement at this time. Exhibit A specifies that EWR should not be arbitrarily restricted to the amounts specified in the legislative 35% goal, and that EWR savings should be aggregated into hourly units in order to allow EWR to be modeled as a resource for the model to select.

Wolverine Power Supply Cooperative

Wolverine Power Supply Cooperative (Wolverine) comments that the future IRP process must support a one-Michigan policy and ensure that all appropriate, and potentially more efficient, options are represented in the process. Specifically, Wolverine recommends that the Commission include a scenario that combines the Upper and Lower Peninsulas. According to Wolverine, this analysis must consider the respective impacts that resources have in the two peninsulas. Additionally, Wolverine comments that to ensure the most efficient and cost-effective use of ratepayer resources, two alternatives from the IRP draft filing requirements within the strawman proposal should be included in the IRP Strawman proposal. Those are: (1) transmission options, in lieu of generation or other upgrades; and (2) including existing and/or proposed resources not owned by the petitioning utility.

The Commission appreciates Wolverine's comments, however, it is not persuaded that requiring a scenario that analyzes combining the peninsulas is warranted at this time. Other commenters expressed a concern that the initial draft included too many required scenarios and sensitivities, and the Commission has endeavored to address that concern. The Commission intends to address Wolverine's comments regarding transmission options and existing and/or proposed resources not owned by the petitioning utility as part of the filing requirements slated to be approved in December 2017.

Consumers Energy Company

Consumers first comments on the DR statewide study and recommends flexibility to use company-specific potential study data, the statewide potential study data, customer enrollment data, and other resources best suited for the utility IRP. Next, Consumers comments that for modeling scenarios, assumptions, and sensitivities for multi-state utilities located in Michigan that already file multi-state IRPs in other jurisdictions, the Staff intentionally excluded both Northern States Power-Wisconsin and I&M in the applicability of any of the outlined scenarios on page 12 of the Strawman Proposal. Consumers recommends including language that specifies the Commission's authority to require supplemental information from these multi-state utilities, if necessary, as part of its evaluation and determination of whether to approve the IRP pursuant to Section 4 of Act 341.

The Commission has included a revision in Exhibit A clarifying that the Commission may require supplemental information from multi-state utilities as part of its evaluation. The

Commission is not persuaded to grant flexibility regarding the use of company-specific potential study data or other resources that the utility deems appropriate for EWR and DR potential in the required scenarios and sensitivities. The Commission finds it appropriate to grant such flexibility for any *additional* scenarios and sensitivities that the utility may wish to include in its IRP. The Commission confirms that the most current state-wide EWR and DR potential study data should be utilized in modeling the required scenarios and sensitivities, and notes that the statewide EWR and demand response potential studies are included in the requirements outlined in MCL 460.6t.

Consumers also comments more specifically on the three proposed scenarios, assumptions, and scenarios.

Business as Usual Scenario

Consumers does not offer comments on the narrative of this scenario, however, the company recommends that the Commission consider changes to the assumptions and sensitivities in this scenario.

1. Fuel Cost Projections

Consumers comments that the BAU sensitivity of increased natural gas fuel price projections by 300% above the BAU natural gas price projection would reflect a natural gas price of about $9/million British thermal unit (MMBtu) in today's dollars escalating to $15 over a 15-year study starting in the current year. Consumers notes that natural gas prices at $15 have not been seen before, and price projections have steadily declined over the past decade. According to Consumers, this sensitivity would provide less valuable insight into the risks associated with investments in natural gas generating units that would be realized by a utility in the first five years of an IRP filing or within the 15-year planning horizon. The company agrees that a sensitivity of higher natural gas prices warrants evaluation, however at a level with a higher probability of occurring during an IRP planning horizon. Consumers recommends adjusting the 300% above BAU natural gas price forecasts to 100%, and include an option to use a two times BAU multiplication factor. Consumers comments that this doubles natural gas prices to between $4 and $6/MMBtu, providing insights into the economic risks of investing in natural gas generation, and potentially causing other generating resources to become more viable.

The Commission agrees that 300% above BAU natural gas prices is too high but nonetheless stresses that the purpose of conducting sensitivity analyses is to evaluate a full range of possibilities--including those possibilities that may not be deemed likely at the present moment. While the Commission appreciates Consumers' suggestion that a high natural gas price sensitivity should be in the $4 to $6/MMBtu range, the Commission disagrees. It is difficult to predict the future, therefore, a robust analysis is warranted. The Commission agrees that natural gas prices 300% above BAU may be higher than necessary to encompass the risk associated with higher natural gas prices, and has revised the high gas price sensitivity to 200% above the BAU forecasted natural gas prices.

Consumers also comments that the BAU sensitivity to reduce the natural gas fuel price projection by 50% of the BAU natural gas fuel price projection would reflect a natural gas fuel price of around $0.5 to $1/MMBtu, potentially driving coal retirements and increased investment in natural gas generation. Consumers recommends not including this sensitivity because the base natural gas fuel price in the BAU already reflects a low natural gas fuel price projection.

The Commission agrees and has removed the low gas price sensitivity from three scenarios, but retains a low gas price sensitivity in the high market price scenario. The high market price variant scenario assumes a higher natural gas price forecast in the description of the scenario, making a low gas price sensitivity relevant.

2. Load Projections

Consumers comments that an assumption that industrial production and demand increases as result of low natural gas prices is included in the scenario. However, Consumers continues, based on historical load forecasts in combination with low natural gas prices, there has not been a correlation between increased industrial demand and production and low natural gas prices. Consumers comments that if the intent of increasing industrial demand and production was to increase load growth, potentially driving additional build, that this can be achieved with the high growth rates at least two times the BAU or a 1% above BAU load growth sensitivity. Therefore, Consumers recommends not including the increased industrial demand and production due to low natural gas price sensitivities, and adding an option for a utility to choose the greater of two times BAU or 1% above BAU load growth.

The Commission agrees that a sensitivity doubling baseline load projections that are very low, will not be productive and agrees with the concept of a minimum amount of spread between the baseline load forecast and a high gas price sensitivity. However, the Commission has modified Exhibit A specifying that a 1.5% increase should be modeled if doubling the BAU demand and energy growth rates results in a spread less than 1.5%. Again, the Commission stresses the need for a robust analysis, and the Commission finds a 1.5% increased demand and energy growth sensitivity to be reasonable, given the potential for new electric uses such as plug-in electric vehicle (EVs). While the Commission appreciates that Consumers has not found a correlation between low natural gas prices and increased industrial demand in its service territory in the past, the Commission is not persuaded to remove that component from the scenario description at this time.

This scenario, according to Consumers, includes a low load growth rate at 50% of the BAU assumption to reflect a depressed economic environment. Consumers provides that current forecasted growth rates for Consumers' bundled load is 0.08% peak and 0.09% generation requirements. The forecasted system load growths are around 0.6% peak and 0.68% for generation requirements. Consumers comments that because these are nearing zero, there would be minimal value or insights gained with this sensitivity. Consumers recommends this sensitivity not be included, and that it is accounted for in the base load forecast.

The Commission agrees and has removed the low load growth sensitivity from all of the required scenarios in Exhibit A. Although this sensitivity has been removed across the board, the Commission expects that the aggressive EWR sensitivity will provide insight into the results that would be expected from a low-load growth sensitivity while meeting a somewhat less aggressive level of EWR.

3. Energy Waste Reduction and Demand Response

Consumers comments that the BAU scenario describes a future with no carbon reductions, some coal retirements due to renewable additions because of the renewable portfolio standards, and flat load growth. With these factors, there is less incentive to achieve annual incremental savings of much greater than 1% to 1.5% under the EWR plan in Public Act 342 of 2016 (Act 342), with the maximum financial incentive available for annual incremental savings of greater than 1.5%. To request a sensitivity to increase EWR to at least the maximum achievable potential levels in the EWR potential study is inconsistent with the circumstances of this scenario. The Company recommends not including the sensitivity to "[i]ncrease the EWR resources to at least the EWR potential study maximum achievable potential levels." Strawman Proposal, page 14. Similarly, there is a request for a sensitivity to increase the combined RE (RE) and EWR to

50% by 2030. The company believes increased RE and EWR would be reflected by the sensitivities included in the Emerging Technologies and Environmental Policy scenarios. Therefore, this sensitivity is not needed in the BAU scenario.

While the Commission acknowledges that the EWR specifications in the scenarios and sensitivities are higher than the minimum levels mandated by statute, the Commission finds it reasonable to include a baseline level of EWR that aligns with the level that would be achieved by utilities when reaching the maximum allowable financial incentive for EWR. Regarding Consumers' comment that an aggressive EWR sensitivity would be inconsistent with the circumstances of the scenario, the Commission reiterates that the future cannot be precisely predicted, creating the need for a robust sensitivity analysis which expressly includes things that are beyond current expectations. The Commission has retained an aggressive EWR sensitivity, based upon the aggressive EWR scenario in the statewide EWR potential study, and has further clarified how it should be modeled in Exhibit A. The Commission agrees that a high RE sensitivity could be included in the Emerging Technologies Scenario and has moved it to that scenario, and has further modified it based on a comment from MEC.

Consumers further comments that the sensitivities for the "Disinterest in Demand Response" assumption provide an extreme lower bound for DR, to the extent that demand response programs are non-existent. Consumers recommends not including this sensitivity because historical and current DR programs could be considered at levels representing a low or disinterest in demand response programs. Additionally, the company and other utilities have offered a consistent level of DR programs, such as Rate GI, for decades, which indicates that DR programs would likely not reach a non-existent level.

The Commission agrees and has removed the "Disinterest in Demand Response" sensitivity.

Emerging Technologies Scenario

Consumers comments that inconsistencies exist within the assumptions and the description of the scenario that do not align with the purpose of the scenario.

> The description of the scenario states: "Load forecasts and fuel price forecasts remain at levels similar to the Business as Usual Scenario." Strawman Proposal, page 15. This statement is inconsistent with a future robust economy. A robust economy would cause higher load growth versus remaining at flat load growth. The Company recommends deleting the statement that load forecasts and fuel price forecasts remain similar to BAU.
>
> The description of the scenario states that it results in "a 35% reduction in costs for demand response, EWR programs, and other emerging technologies" and includes an assumption that "[t]echnology costs for EWR and demand response programs will be determined by their respective potential studies." Strawman Proposal, page 15. It is not clear whether the technology costs are determined by the respective studies or if the costs are to be reduced by 35% from some forecasted amount of EWR, Demand Response, and emerging technologies. The EWR and Demand Response potential studies forecast cost decreases in technology, supported by research. The Company recommends that technology costs be determined by their respective potential studies rather than assuming an additional 35% cost reduction. The Company recommends replacing the "35% reduction in costs" with "reduced costs."
>
> The description of the scenario states: "No carbon reductions are modeled, but some reductions occur due to age- or economics-related coal unit retirements." Strawman Proposal, page 15. This is inconsistent with the assumption that states: "Assumptions for unit retirements are not made unless affirmative, public statements to that effect are made by the owner of the generation asset." Strawman Proposal, page 15. The company recommends not including this part of the retirement assumption to better align with the age- and economics-related coal unit retirements driven by the purpose of the scenario.
>
> The assumption that technology costs of thermal units remain stable and escalate at low to moderate escalation rates contains inconsistency in escalation rates (e.g. low versus moderate). The company recommends a mid-range escalation rate. Additionally, increased well productivity and supply chain efficiencies keep natural gas prices low.

The Commission appreciates the comment that the assumption of a robust economy is not aligned with the assumption that load forecasts and fuel price forecasts remain at levels similar to BAU levels. The Commission has resolved this discrepancy by removing the concept of a robust economy from the scenario. The Commission is not convinced that assumptions for a robust economy are necessary to drive cost reductions in emerging technologies, such as the declines in wind and solar costs that have been seen over the past several years. The Commission finds the insights to be gained from analyzing reduced costs for emerging technologies in a BAU economy a worthy cause. Because a high load growth sensitivity and a high natural gas price sensitivity are both retained, the Commission expects to gain some insights from emerging technologies from a more robust economy as well, through the required sensitivity analyses.

The Commission has already clarified that costs that included the statewide potential studies should be used in the required scenarios and sensitivities and the Commission further clarifies in Exhibit A that the 35% cost reduction means costs that are 35% lower than those included in the statewide potential studies. The Commission clarifies in Exhibit A that units that are not owned by the utility shall not be hard-wired to retire during the study period unless affirmative, public statements to that effect are made by the owner of the generation asset. The Commission further clarifies that it would be appropriate for the utility to include known plans for retirements of any of its owned units and the Commission expects that letting the model retire its owned units based upon economics will help the utility make informed decisions about future retirements. The Commission clarifies that in the Emerging Technologies Scenario, that the utility's coal units not explicitly assumed to retire by the utility, should be allowed to retire in the model based on economics. The Commission agrees with Consumers' comment regarding the technology costs for thermal units and has incorporated the suggested change reflecting moderate escalation rates in Exhibit A.

1. Fuel Cost Projections

The company offers the same comments given above for the BAU Fuel Cost Projections.

For consistency purposes, the Commission has made similar changes to all three of the required scenarios applicable in the Lower Peninsula, and for brevity, the Commission will not address further comments that it has already addressed herein.

2. Load Projections

Consumers comments that a high growth rate is needed to reflect a robust economy. The company agrees with including the sensitivity to increase the growth rate by a factor of two above the BAU assumption. However, Consumers recommends adding an option to choose a 1% growth above BAU because existing forecasted growth rates are nearing zero.

Consumers further comments that the scenario includes a low growth rate at 50% of the BAU assumption reflecting a depressed economic environment. The company recommends adjusting this sensitivity to the utilities' BAU load forecast as stated in the comments given for the BAU Load Projections and it be included as part of the scenario narrative.

The Commission has removed the low load growth sensitivity for consistency and the Commission has removed the concept of a robust economy being necessary for this scenario. The Commission does not find it necessary to model a low load growth sensitivity and has removed it.

3. Energy Waste Reduction

Consumers provides that the Strawman Proposal recommends a sensitivity to ramp up EWR savings to at least 2.5% of prior year sales over the course of four years. Because the scenario narrative includes a high EWR case, it can be assumed that the base load and demand forecasts for this scenario will already include a ramp up of EWR. A separate sensitivity to reflect this ramp up is not needed. If a specified ramp rate is needed, the company agrees to include a ramp up of EWR savings to at least 2.5% of prior year sales over the course of four years.

While the Commission finds it likely that this scenario will result in higher levels of EWR, the Commission also finds value in explicitly modeling the high EWR sensitivity in case the resulting amount of EWR without the sensitivity is lower than specified by the high EWR sensitivity. The high EWR sensitivity has been retained.

4. Renewable Energy Costs

Consumers offers no comments to these sensitivities.

5. Transportation Energy

The proposed sensitivity in this scenario is to increase the percent of EVs in Michigan. The Staff proposes a 10% increase by 2025. Because the scenario narrative reflects a robust economy where technology advancements are on the rise, Consumers comments, an increase of EVs can be included in the scenario narrative through the load forecast versus a separate sensitivity. Consumers states that this will help align the load forecasts with the future world to be modeled and reduce modeling run time.

The Commission appreciates Consumers' concepts regarding the transportation energy sensitivity. Without making any assumptions regarding the impact of EVs on the load forecast in this scenario, as the Commission acknowledges may be subjective until more experience deploying EVs and associated infrastructure is achieved, the Commission has removed this sensitivity altogether in order to reduce the amount of required sensitivities.

6. Large Electric Users

Consumers comments that the large electric users sensitivity in the Emerging Technologies scenario assumes a level of reduced load due to customers' use of combined heat and power (CHP), batteries, and/or behind the meter generation to offset high electric rates. Consumers recommends accounting for this load reduction in the base load forecast of the scenario versus a separate sensitivity.

Similar to the discussion regarding the impact of EVs on the load forecast, the Commission finds that the amount of reduced load due to customers' use of CHP may be subjective. Without adding any assumptions regarding specific levels of CHP in the load forecast in this scenario, the Commission has removed this sensitivity altogether in order to reduce the amount of required sensitivities.

Environmental Policy Scenario

Consumers lists two perceived inconsistencies within the assumptions and the description of the scenario. First, Consumers provides that an assumption is made in this scenario that natural gas prices to be utilized "are consistent with business as usual projections." However, the description of the scenario also states an increased reliance on gas, which Consumers believes indicates the base natural gas fuel price projection should be higher than the BAU case. According to Consumers, an adjustment in wording, or not including this assumption, eliminates these conflicting statements and will align the assumption with the scenario.

Second, Consumers comments that the description states some coal retirements will occur; however, a listed assumption states that coal units will be retired reflecting economics. Because the primary characteristic of the scenario is carbon regulations, Consumers states that it should be assumed coal retirements are considered based on the 30% carbon reduction requirement versus the economics of the unit. Consumers recommends adjusting the assumption and the description of the scenario to state coal retirements will be based on carbon reduction targets.

The Commission has elected to retain the concept that gas prices are consistent with BAU in the Environmental Policy Scenario and has also elected to retain the concept that coal retirements lead to an increased reliance on gas. While it may be true that an increased reliance on gas could lead to higher gas prices, the Commission finds that differing levels of increased reliance on gas would lead to differing levels of gas prices, and no specific level of increased reliance on gas has been specified. In fact, the Commission expects that the natural gas price assumed in the model will drive the level of reliance on gas in this scenario. Therefore, the Commission prefers to include a high gas price sensitivity to capture the impact of higher gas prices as opposed to increasing the gas price in the description of the scenario.

The Commission has clarified in Exhibit A that the utility's coal units will be retired based upon carbon emissions *and* economics, if applicable in the Environmental Policy Scenario. The Commission expects that units would first be retired based upon allowable carbon emissions levels, and then after the carbon emission levels have been met, future retirements would occur based upon economics.

1. Fuel Cost Projections

Consumers recommends using the high natural gas fuel price forecast recommended by the company for the BAU case be included in the scenario narrative. Therefore, Consumers believes that a separate high natural gas fuel price sensitivity is not required for this scenario.
For the low natural gas fuel price sensitivity, the company offers the same comments given above for the BAU Fuel Cost Projections.

Because the Commission is not adopting a high natural gas price in the description of this scenario, the Commission is retaining the high natural gas price sensitivity.

2. Load Projections

Consumers comments that a high load growth rate is not needed to reflect a robust economy as is proposed for the Emerging Technologies scenario. Instead, Consumers suggests, the scenario is for a suppressed economy, meaning growth rates remain flat or decline. Consumers recommends deleting the sensitivity on high growth rates, and including the BAU load forecast in the this scenario. Consumers believes this will promote consistency in the assumptions built for the Environmental Policy scenario, and reduce unnecessary modeling run time for utilities.

Consumers further comments that this scenario includes a low load growth rate at 50% of the BAU assumption to reflect a depressed economic environment. Consumers recommends adjusting this sensitivity to the utilities' BAU load forecast as stated in the comments given for the BAU Load Projections. According to Consumers, low load growth rates are expected because coal retirements are driven by environmental regulations and not a robust economy.

The Commission agrees that the BAU load forecast is appropriate to include in the scenario narrative, but also finds value in exploring the potential impact of higher load growth in an environmental policy scenario. As previously discussed, the Commission has removed the requirement for a low load growth sensitivity for similar reasons as in the BAU scenario.

3. Energy Waste Reduction

Consumers states that the Environmental Policy scenario assumes technology costs for EWR remain similar to BAU and the load growth is flat or declining. Because the EWR costs remain similar to BAU and are not significantly reduced due to the economy not being robust, Consumers suggests a sensitivity of the maximum achievable potential level would not be a likely investment. Consumers recommends excluding this sensitivity as it is not consistent with the assumptions.

The Commission disagrees and expects that high levels of EWR should be analyzed in an Environmental Policy scenario because it is an option that could potentially be used to lower the overall level of emissions in the state.

4. Transportation Energy

Consumers recommends including the increased use of EVs load forecast as part of the scenario narrative versus a separate sensitivity. According to Consumers, this helps align the load forecasts with the future world to be modeled and reduce modeling run time.

For similar reasons as previously discussed, the Commission has removed the requirement for a transportation energy sensitivity from this scenario and declines to modify the base load forecast to include the potential impact from transportation energy.

5. Large Electric Users

Consumers comments that the Large Electric Users sensitivity in the Environmental Policy scenario assumes a level of reduced load due to customers' use of CHP, batteries, and/or behind the meter generation to offset high electric rates. The company recommends accounting for this load reduction in the base load forecast of the scenario versus a separate sensitivity. Consumers states that this helps align the load forecasts with the future world to be modeled and reduce modeling run time.

For similar reasons as previously discussed, the Commission has removed the requirement for a large electric users sensitivity from this scenario and declines to modify the base load forecast to include the potential load reduction.

6. Additional Integrated Resource Planning Requirements and Assumptions

Consumers requests the Commission to modify "stakeholder" requirements to be consistent with a public outreach process if included as part of the IRP Filing Requirements.

The Commission will address stakeholder engagement in Case No. U-18461.

Association of Businesses Advocating Tariff Equity

Defining the Base Case

The Association of Businesses Advocating Tariff Equity (ABATE) urges the Commission to closely scrutinize how each utility characterizes its base case (or status quo) in all subsequent IRP proceedings. ABATE believes the Commission should provide adequate guidance regarding how it views the base case. ABATE further provides that, ideally, the Commission will endeavor to assign a precise definition to the term. ABATE comments that absent universal and unambiguous parameters, a utility may be tempted to define its base case in a way that most supports the utility's desired outcome. To determine the appropriate parameters for the base case, the Commission should look to Section 6t(5) of Act 341 for guidance. In addition to resources currently under contract or already present in a utility's portfolio, ABATE suggests that IRP proposals should include Commission-approved resources that are not yet online — as long as the utility has a tentative idea about when the resource will go live.

ABATE also comments that even if the Commission declines to adopt an exact definition for the base case, it should still instruct the utilities to apply the same base case for all scenarios presented in their respective IRP cases. ABATE comments that utilities should present several varying predictions about the future in the form of scenarios. According to ABATE, the status quo, however, is known and measurable and unless a utility offers a compelling reason to deviate from a single interpretation of its status quo, the Commission should mandate that utilities apply a consistent base case in each scenario presented.

The Commission has prescribed a required base case, or BAU scenario, in Exhibit A and has endeavored to provide the necessary guidance. The Commission agrees with ABATE that the utilities should present several different future scenarios and encourages the utilities to include additional scenarios over and above those specified in Exhibit A.

Scenarios

1. Expansion of Choice

ABATE comments that the Commission should require that utilities include a sensitivity gauge in each of their scenarios that reflects the impact related to an increase of the choice cap. ABATE suggests that utilities utilize the number of customers in their respective choice queues as a reference point.

The Commission declines to require this sensitivity at this time but has required an analysis showing 50% of the load served by alternative electric suppliers returning to the utility to understand the impact on the utility's planning needs.

2. Data Requirements

ABATE provides that the Commission should make it clear that three is the *minimum* number of modeling scenarios required. ABATE notes that it would not be unreasonable to require five or six scenarios. ABATE acknowledges that more scenarios naturally translates to more work for the utilities, but argues that the benefits of additional juxtapositions will increase transparency and allow for the Commission to make a more informed decision. Regardless of the number of scenarios, ABATE believes the Commission should require that utilities make certain information available to stakeholders as early as possible, and preferably prior to the prehearing conference. At a minimum, the utility should provide: (1) the name of any model(s) used; (2) copies of the corresponding user manuals; (3) a description of each output report available; (4) modeling inputs/outputs in a searchable format (e.g. Excel); and (5) modeling inputs/outputs in the model-dependent binary format to parties that obtain a license. ABATE notes that this non-exhaustive list is representative of the sort of data that parties routinely seek and receive through the discovery process. By requiring utilities to produce the data earlier in the process, ABATE believes the Commission is merely removing an artificial delay. Additionally, ABATE comments that the Commission should make it clear that utilities must produce the underlying data and work papers used to support their IRPs. ABATE suggests that the Commission require utilities to share all IRP-related data in native format, with formulas intact.

The Commission agrees with ABATE regarding many of the points raised regarding data requirements and expects to address data requirements in Case No. U-18461.

Taxes and Regulations

ABATE believes that the Commission should require utilities with renewable resources in their portfolio to include a sensitivity that assumes a decrease in the federal corporate income tax rate, which will affect the revenue value of tax credits. Furthermore, ABATE continues, these same utilities should be required to disclose how a decrease in the corporate income tax rate would affect certain accounting categories (e.g., net operating losses, deferred tax assets, etc.). ABATE comments that the intent of this recommendation is to ensure that the stakeholders gain a proper understanding of the utility's reliance on green energy-based tax incentives.

ABATE further comments that the Commission should require that scenarios exploring the impact of regulatory changes contemplate all pending environmental legislation (state and federal), as well as any laws currently stayed by the courts. These scenarios should also inspect the implications of a decrease in environmental regulation.

Regarding RE tax credits, the Commission has included the assumption that existing RE tax credits will continue pursuant to current law. Because the RE tax credits have a near-term expiration date, the Commission does not find it necessary to require a sensitivity assuming a decrease in the federal corporate income tax rate at this time. The Commission agrees that all pending environmental legislation and pending regulatory changes should be addressed in scenarios and sensitivities included in utility IRPs.

Demand Response

ABATE notes that to comply with Section 6t(1)(b) of Act 341, the Staff determined that the assessment for use of demand response programs would best be comprised of two parts: a technical study and a market assessment. The Strawman Proposal indicates that the market assessment will examine the potential for demand response for large commercial and industrial (LCI) customers through surveys, interviews, and analysis of the customer class. ABATE requests that the Commission augment this language with additional details regarding the surveys and interviews. ABATE comments that to truly ascertain the customer's capability, desire, and motivation to participate in demand response programs, the Commission needs to require a sufficient level of customer engagement. ABATE suggests that it would be beneficial for the surveys and interviews to account for the ebb and flow of business and that soliciting input regarding DR from the largest customers is a logical first step. ABATE notes that utilities may, however, also be able to gain valuable insight from polling residential customers. ABATE is not suggesting that the utilities contact each residential customer individually, but if the aggregation of these smaller customers is possible, then evaluating the effects of varying degrees of residential participation becomes a reality.

The Commission appreciates ABATE's comments regarding demand response. The Commission has updated the section of Exhibit A dealing with demand response.

DTE Electric Company

Energy Waste Reduction and Energy Waste Reduction Potential Study

DTE Electric comments that the EWR BAU case includes 1.50% savings in the IRP Modeling Input Assumptions. DTE Electric acknowledges that this annual incremental savings assumption could be driven by utility efforts to maximize the performance incentive by targeting the highest savings tier allowed by legislation. However, DTE believes that this may be an aggressive level of savings to establish as a BAU case as this level of energy savings has not yet been achieved in Michigan. DTE Electric points to the American Council for an Energy-Efficient Economy (ACEEE) 2017 Utility Scorecard that identifies only six utilities in the nation that achieved savings of 1.50% or greater. DTE Electric comments that per Act 342, the legislative minimum is 1.00% through 2021. According to DTE Electric, the average percent savings of the 52 utilities included in the ACEEE 2017 Utility Scorecard is 0.9%, indicating the legislative minimum of 1.00% is more aligned with "usual" EE operations.

DTE Electric further comments that the IRP Modeling Input Assumptions for EWR savings includes ramping annual savings up to 2.50% by 2021 and maintaining that level of incremental savings. DTE Electric comments that it is not clear what source was used to determine a savings level of 2.50% since there is no explanation or supporting data provided in the Strawman Proposal document that would support this recommendation. DTE Electric believes a higher level of EWR savings modeled in an IRP should be reflective of the savings potential identified in a utility's potential study. If there is not enough potential to achieve 2.50% savings, it may not be feasible to allow the model to select that level of savings.

DTE Electric further claims that assuming utilities will achieve EWR reductions of 2.50% by 2021 may create improbable scenarios because there may not be enough potential savings, may lead to disruptions associated with scaling programs up and down when potential runs out, and/or may impact customer affordability. DTE Electric points out that only two utilities (Massachusetts

Electric, MA and NSTAR Electric, MA) achieved savings of 2.50% or greater per the ACEEE 2017 Utility Scorecard, and at a cost greater than 10% of revenue. Furthermore, DTE Electric continues, comparing what another jurisdiction has achieved is not an appropriate method of benchmarking what may be achieved in Michigan.

DTE Electric notes that there are many factors that determine an achievable level of savings within a jurisdiction, such as avoided cost, regulatory construct, territory specific economics, program mix, and program maturity. In addition, what a utility has achieved in the past is not a good indicator of what may be achieved going forward given the many challenges facing EE, such as: (1) Depletion of low-cost high potential programs; (2) diminishing lighting potential because of the Energy Independence and Security Act (EISA) and the success of market penetration for LEDs; (3) rising customer baseline of installed efficiency as EWR programs and other factors make customers more energy-conscious; (4) increases in marketing costs when attempting to capture hard-to-reach segments; and (5) uncertainty around design delivery and technologies not yet developed.

DTE Electric believes that comparing what a utility achieves on an annual incremental basis is also not a good indicator of the long-term cumulative impact of EWR on a utility's load profile. DTE Electric observes, for example, if a utility offers a measure with a 5-year life with 1% savings and at the end of that measure's useful life the utility incentivizes the customer to replace the measure, they would not be reducing the load profile by a total of 2%, but simply maintaining the 1% savings. Although, on an annual incremental basis the utility would claim 1% savings in both years.

DTE Electric comments that there are several reasons why a customer incentive level of 100% of measure costs is not recommended for EWR achievable potential sensitivities. First, DTE explains that an incentive level of 50% of measure costs assumed in the statewide potential study for the achievable potential scenarios is a reasonable target based on the current financial incentive levels for program participants used by Michigan utilities for their existing EWR programs. Second, DTE Electric points out that GDS Associates, Inc. has reviewed other EWR potential studies conducted in the United States and that the incentive levels used in several studies reviewed by GDS as well as actual experience with incentive levels in other states confirm that an incentive level assumption of 50% or below is commonly used. DTE Electric provides for example, the New York State Energy Research & Development Authority electric EWR achievable potential study completed by Optimal Energy in 2006 assumed incentive levels in the range of 20% to 50%. And third, DTE Electric provides that the highly recognized 2004 National EE Best Practices Study concluded that use of an incentive level of 100% of measure costs is not recommended as a program strategy. According to DTE Electric, this national best practices study concluded that it is very important to limit incentives to participants so that they do not exceed a pre-determined portion of average or customer-specific incremental cost estimates. The report states that this step is critical to avoid grossly overpaying for energy savings. DTE Electric further comments that this best practices report also notes that if incentives are set too high, free-ridership problems will increase significantly. Free riders dilute the market impact of program dollars.

DTE Electric comments that financial incentives are only one of many important programmatic marketing tools. The utility provides that program designs and program logic models also need to make use of other education, training and marketing tools to maximize consumer awareness and understanding of energy efficient products. According to DTE Electric, a program manager can ramp up or down expenditures for the mix of marketing tools to maximize program participation and savings. DTE Electric points to the February 2010 National Action

Plan for Energy Efficiency Report titled Customer Incentives for Energy Efficiency Through Program Offerings provides that incentives can be used in conjunction with other program strategies to achieve market transformation, whereby there is a lasting change in the availability and demand for energy-efficient goods and services. In addition, DTE Electric continues, the report states that well-designed incentives address the key market barriers in the target market. DTE Electric believes that financial incentives are designed to be just high enough to gain the desired level of program participation. In some cases, financial incentives can be bundled with financing, information, or technical services to reach program participation and energy savings goals at lower total program cost than using financial incentives alone.

While the Commission acknowledges that the EWR specifications in the scenarios and sensitivities are higher than the levels mandated by statute, the Commission finds it reasonable to include a baseline level of EWR that aligns with the level that would be achieved by utilities when reaching the maximum allowable financial incentive for EWR. The Commission clarifies that the high EWR sensitivity that assumes that EWR ramps up to 2.5% annual savings and remains at high levels is based upon the aggressive scenario in the statewide EWR potential study. The Commission notes that Section 6t of Act 341 requires the Commission to perform statewide EWR and demand response potential studies. The Commission has elected to retain an aggressive EWR sensitivity, based upon the scenario in the statewide EWR potential study, and has further clarified how it should be modeled in Exhibit A.

Planning Reserve Margins and Local Clearing Requirements

DTE Electric provides clarifications for the Commission to consider regarding MISO's forward looking planning reserve margin (PRM) and local reliability requirement (LRR). DTE Electric comments that while MISO does publish Planning Reserve Margins for the next ten years in its annual report, only three of the ten years are actually modeled – the other seven are only interpolations of the modeled years. DTE Electric points out that MISO does not calculate the LRR for each of the next three years in its annual report. Similar to the PRM, MISO selects three years (the prompt year, one year in future years 2-5, and one year in future years 6-10) to calculate the LRR. DTE Electric provides for example, in the 2017 Loss of Load Expectation Study Report, MISO studied and published LRR values for planning years 2017-18, 2019-20, and 2026-27.

The Commission appreciates DTE Electric's clarifications on the PRMR and the LRR. The Commission has reflected these clarifications in Exhibit A.

Modeling Scenarios, Sensitivities and Assumptions

1. The three MISO Zone 7 Scenarios

DTE Electric comments that the sentence referring that natural gas prices utilized are "consistent" with BAU projections as projected in the US Energy Information Administration's (EIA) most recent Annual Energy Outlook reference case, seems inconsistent with the sources list presented in Section IX. DTE Electric would prefer to use its own documented forecast and justify its applicability. The word "consistent" used in this context is confusing.

The Commission disagrees. The EIA's Annual Energy Outlook is specified in the list of potential sources in section IX and the scenario description is further clarifying that a forecast consistent with the EIA's Annual Energy Outlook reference case should be utilized for the scenario. The Commission clarifies that the word consistent was chosen on purpose in order to allow the utility to make small deviations, but not necessarily large deviations, from the specified forecast in the scenario.

2. Sensitivities

Regarding the fuel cost projections, DTE Electric recommends that there should be a transition period from today's spot price to get to the higher price and not transition to 300% higher immediately. Additionally, DTE Electric believes the 300% higher is excessive. DTE Electric recommends 150% to 200% to be symmetric with the 50% low case. DTE Electric points out that MISO uses +/- 30% in their sensitivities.

The Commission agrees to allow for a transition period from today's spot price to the gas prices specified in the sensitivities and Exhibit A was updated to reflect this suggestion. As previously discussed, the Commission also agrees to reduce the high gas price sensitivity from 300% to 200%.

Regarding the load projections, DTE Electric recommends adding "at least half." At low load growth rates in the base case, halving 0.2% to 0.1%, for example, would not show significant change.

As previously discussed, the Commission has elected to remove the requirement for the low load growth sensitivity.

Scenario 2

DTE Electric comments that the phrase, "technology costs for EWR and DR programs will be determined by their respective potential studies," assumes that you take the potential study costs and then lower by 35%, per the opening paragraph in this section. DTE Electric requests clarification on this point. DTE Electric seeks further clarification on whether renewables are included in the "other emerging technologies," that need to reduce costs by 35%.

DTE Electric comments that the sensitivities need to allow for flexibility that balances analysis of stakeholder concerns with a reasonable number of model runs to ensure that the IRP process is efficient and can be conducted in a reasonable amount of time. Specifically, DTE Electric notes, some sensitivities would require a "big model" run with full optimization of the area, while other sensitivity changes would not have a material impact on the market results. In order to prevent an onerous amount of big model runs by utilities and other interested parties who will be doing modeling, DTE Electric recommends the Commission allow for utility or Michigan only sensitivities in the load change sensitivities, the EWR increased level sensitivities, the combined use of RE and EWR to 50% by 2030 sensitivity, and the large electric user sensitivity.

The Commission agrees and clarifies that the 35% reduction in EWR and demand response costs should be applied to the costs specified in the statewide potential studies. The Commission is sympathetic to the comments regarding the need to balance stakeholder concerns with a reasonable number of model runs and has endeavored to significantly reduce the number of required sensitivities. However, the Commission encourages the utilities to include additional scenarios and sensitivities and likewise encourages robust stakeholder engagement during the development of the IRP in order to address any remaining stakeholder concerns.

Section IX Modeling Input Assumptions and Sources

DTE Electric has concerns that allowing the model to select retirement of existing generation resources in each sensitivity and scenario could limit or prolong optimization by adding extra alternatives (retire or keep). Depending on the utility, the number of units they have, and the number of years in the study, the problem size quickly becomes unmanageable. DTE Electric suggests the following modification: "In modeling each scenario and sensitivity evaluated as part of the IRP process, the utility shall describe how unit retirements were evaluated."

The Commission clarifies that it not necessary to allow the model to retire units economically that it does not own, however the Commission finds value in letting the model retire company-owned units based upon economics. The Commission is sympathetic to concerns related to modeling time and has specified specific situations in the Emerging Technologies Scenario and the Environmental Policy Scenario where only the utility's remaining coal units, as opposed to all of the utility's units, be available for the model to retire based upon economics. In the BAU Scenario and the High Market Price Variant Scenario, the utilities are allowed more flexibility in the methodology used to determine the retirement of utility-owned units, but are also not precluded from allowing the model to retire them based upon economics. The reduction in scope for the requirements to economically model retirements, coupled with a reduced number of sensitivities, are intended to at least partially remedy DTE Electric's concerns regarding unmanageable problem size. The Commission also clarifies in Section X that the utility shall clearly identify in each scenario and sensitivity, all unit retirement assumptions, and unless otherwise specified in the description of the *required* scenarios and sensitivities, the utility has flexibility to allow the model to select retirement of the utility's existing generation resources, rather than limiting retirements to input assumptions. The Commission reiterates, that any additional scenario and sensitivity analyses presented in an IRP that are over and above the required scenarios and sensitivities, may include differing assumptions and sources, including retirement assumptions, as deemed appropriate by the utility.

Michigan Energy Innovation Business Council

The Michigan Energy Innovation Business Council (EIBC) supports a strong IRP process that reflects the full range of available energy generation and load management options.

EIBC suggests expanded consideration of EWR to include all cost effective EWR measures. EIBC comments that EWR remains the most cost-effective means of meeting Michigan's energy needs. EIBC believes, however, that the Strawman proposal fails to contemplate the full range of

EWR by limiting assumed EWR investments to 1.5% for utilities earning financial incentive and 1% for non-incentive earning utilities.

EIBC recommends adding specificity to consideration of non-utility owned energy resources as part of planning process. Although EIBC is pleased with the Scenario 2 requirement for utilities to consider non-utility resources prior to and during the modeling process, the Commission should provide greater specificity and/or inclusion of the specific planning parameters in the sensitivities that guide utility modeling in the area.

EIBC recommends expanding risk considerations and analysis of the benefits of diversity of generation resources. EIBC comments that Act 341 requires the Commission to consider an analysis of commodity cost risk and the benefits of a diversity of generation supply to be included to determine if the IRP meets the most reasonable and prudent standard. EIBC comments that the Strawman proposal fails to adequately include risk considerations in the IRP planning process. EIBC encourages expanding the consideration of commodity price risk as an element in the planning process.

EIBC recommends expanding modeling based on emerging customer preferences and growing sophistication in energy procurement and management. EIBC notes the growing demand for RE to meet RE or sustainability targets set by individual companies. EIBC comments that modeling utility projections relating to the scale of this potential demand as a key driver of additional RE generation beyond the renewable portfolio standard of 15% by 2021.

EIBC suggests better integration of DR and load management opportunities. EIBC encourages the Commission to continue its efforts to fully consider DR as a resource that levels the playing field between demand and supply side alternatives in an effort to maximize ratepayer savings.

EIBC recommends coordinating the IRP process with distribution and transmission planning activities. EIBC also encourages coordinating with other planning processes such as the Code of Conduct rulemaking process, the process for establishing avoided costs under PURPA, the development of a tariff for distributed generation, issues related to plug-in EV proceedings, and efforts to voluntarily control load management.

The Commission has addressed EIBC's concern that EWR levels may be unnecessarily restricted in the scenarios by requiring aggressive EWR sensitivities. The Commission has included a required high gas price sensitivity in order to capture the risk of higher gas prices on future utility plans and also expects to address the broader issue of risk assessment in Case No. U-18461. Addressing EIBC's concern that higher levels of RE should be modeled, the Commission has included a sensitivity to the Emerging Technologies Scenario specifically requiring the utility to model 25% by 2030 renewable portfolio standard. The Commission agrees with EIBC that demand-side and supply-side resources should compete on a level playing field and finds the requirement in Section X to consider all supply-side and demand side resources on equal merit addresses this comment.

Energy Storage Association

The Energy Storage Association (ESA) recommends that the Commission include front-of-meter, distribution- and transmission-connected energy storage to the Emerging Technologies scenario and suggests that considerations of alternatives to traditional transmission and distribution investments include energy storage.

ESA recommends that the Commission consider the following guiding principles: (1) Any prudency determination for new resource acquisition should be incumbent upon consideration of the full range of alternatives, including energy storage; (2) IRPs should institute sub-hourly modeling to increase the granularity of analysis and better inform optimal portfolio selection, particularly as the need for grid flexibility increases; (3) IRPs should consider the net cost of capacity additions, that is, the capital costs adjusted by the operational and other system benefits that a given resource can provide; and (4) IRPs should be transparent with cost information and assumptions, as well as use up-to-date cost inputs to ensure that utilities are selecting the most-competitively priced resources.

ESA further recommends that the Commission include energy storage as a transmission-connected asset in the Emerging Technologies scenario in the Strawman Proposal. ESA notes that throughout the document, energy storage appears to be considered only as a customer-sited distributed energy resource (DER). According to ESA, focusing exclusively on incorporating energy storage as a DER misses the critical contribution that energy storage can provide to the system and ratepayers as a transmission-connected asset. ESA comments that advanced storage technologies are transmission connected in the U.S. at scales of up to 30 MW today and are being chosen as cost-effective and viable alternatives to traditional capacity solutions.

In addition to including front-of-meter energy storage in the Emerging Technology scenario, ESA recommends also including declining cost curve sensitivity for energy storage in the Emerging Technologies section. The Commission's inclusion of assumptions that battery technologies will continue to experience a declining cost curve is an important assumption.

ESA recommends that in addition to requiring utilities to model sensitivities that include a rapidly declining cost curve, the Commission require that utilities use the most current publicly available cost data for energy storage and refers to ESA's 2016 primer on including energy storage in utility IRPs. Energy storage serves a wide variety of applications and services beyond its use as a behind-the-meter distributed generation asset. ESA notes that all the scenarios and sensitivities should be contemplating the use of alternatives to traditional investment, including energy storage.

The Commission acknowledges that it is establishing this new IRP framework at a time when there is tremendous change in our energy landscape with power plants retiring and new energy technologies such as energy storage and distributed generation becoming more prevalent. While IRP has been in practice by utilities across the country for decades with fairly well-established modeling tools and approaches, the Commission recognizes the need to ensure the modeling evolves over time in order for utilities and the Commission to make well-informed decisions that will benefit customers in the long run and reduce risk under uncertain market conditions. That is, the Commission stresses the need to ensure best practices are deployed in the resource modeling to identify system needs and to evaluate different resource options to meet those needs in order for the costs, benefits, and risks to be understood and compared in this dynamic environment. Given that energy storage is rapidly evolving with declining cost profiles and can serve multiple system needs, the Commission appreciates the ESA's suggestions geared at ensuring that energy storage is properly considered through the resource planning and acquisition/construction process. With that said, the Commission does not believe it is appropriate at this time to mandate the use of sub-hourly modeling across the board given that this level of granularity is not typical in long-term resource expansion models spanning 15 to 20 years, or even longer time horizons. The Commission encourages utilities to consider more targeted modeling where it may be necessary to ensure that non-traditional alternatives are properly considered. Moreover, the Commission agrees with the Energy Storage Association that energy storage should not be limited to small-scale storage options, such as distributed energy resources. The Commission has added a revision to the

Emerging Technologies Scenario specifying that larger grid-scale storage options should also be evaluated.

The Commission also agrees that the IRPs should consider, to the extent possible, the net cost of capacity additions, that is, the capital costs adjusted by the operational and other system benefits that a given resource can provide. The Commission is sympathetic to the complexities that this could present in modeling given the level of granularity that may be needed and recognizes that the net cost analysis may evolve over time with future iterations of the IRPs. Notwithstanding, given the most reasonable and prudent statutory standard, it is important to not become myopic in this planning process when evaluating system needs and the benefits different resources can offer simply because of constraints associated with today's modeling tools. Furthermore, the Commission agrees with ESA that the IRPs be transparent with cost information and assumptions, use up-to-date cost inputs, and ensure that utilities are selecting the most competitively-priced resources.

Michigan Environmental Council

The Michigan Environmental Council (MEC) comments that the list of applicable state laws omits the MEPA. MEC states that MEPA applies not only to decisions to authorize the construction and operation of a new emitting facility, but also to decisions of the Commission to approve an IRP. MEC, therefore, urges the Commission to specifically list the MEPA as one of the state laws which a utility is required to demonstrate compliance with through its IRP.

As previously discussed, the Commission has included MEPA in the section regarding environmental laws and regulations.

<u>Recommended changes to Scenario 1</u>

1. Sensitivity 4 - Demand Response

MEC comments that this sensitivity should be expanded to include investments in DR programs that are 100% larger than current programs over a three-year period.

While the Commission does not disagree with MEC regarding the concept of this proposed sensitivity, the Commission has not added the suggested 100% increase in DR programs to the BAU Scenario. Instead, the Commission expects that higher levels of DR will surface in the required Emerging Technologies Scenario where demand response costs are reduced by 35% from the costs in the state-wide potential study.

2. Sensitivity 5 - Combined Energy Waste Reduction and Renewable Energy

MEC provides that in order to have results that are more helpful, sensitivity 5 should focus solely on RE. Based on the data derived from both sensitivity 3 and 5, parties can decide if further evaluation is necessary, which includes a blending of the two resources. MEC suggests that utilities be required to model a 100% increase between 2021 and 2030 as opposed to the current blended proposal included in sensitivity 5.

The Commission agrees with MEC that it may be more helpful to separate the sensitivities evaluating higher levels of EWR and RE. Although somewhat less aggressive than MEC's specific recommendation, the Commission has added a required sensitivity to the Emerging Technologies Scenario requiring 25% RE by 2030.

<u>Recommended changes to Scenario No. 2</u>

1. Plant retirements

MEC comments that the language included within Scenario 2 is ambiguous and arguably in conflict with itself. First, it states that retirements are defined by the utility, but in the next sentence states, it is stated that retirement of all coal units except the most efficient should be considered. MEC believes that this approach allows a utility to avoid doing any meaningful analysis of whether its coal units are cost-effective assets which should remain in rate base. MEC argues that the process should assume older, less efficient assets will be retired, with the burden on the utility to show they remain cost-effective assets to serve their customers. MEC comments that it should be clear within the scenarios that the utility as part of an IRP process should conduct a unit-by-unit analysis of their fleet and justify its future inclusion within rate base.

As previously discussed, the Commission has clarified the retirement assumptions in each required scenario in Exhibit A. The Commission agrees with MEC, and has included a requirement for the utility to economically model retirements of any of its existing coal units not already assumed to retire during the study period.

2. Scenario 2 Description - Inconsistent Statements on Energy Waste Reduction Costs

MEC comments that the language should be clarified to make it clear that the scenario should use a cost curve which is 35% below the number used in the demand response and in EWR cost studies.

The Commission agrees and clarified that the costs should be 35% below the costs in the state-wide potential studies.

Sierra Club, Earthjustice, Union of Concerned Scientists, Natural Resources Defense Council, Ecology Center, 5 Lakes Energy, and Environmental Law and Policy Center

The environmental group (EG) comments that Scenario 3, under Section VIII, does not explicitly state how the referenced 30 percent carbon reduction will be achieved - for example, as a result of a hard cap on emissions or through the application of a carbon price. The EG recommends that the Staff clarify this distinction and note explicitly that the results of this scenario must achieve the stated reduction in emissions.

The Commission clarified that carbon reductions should be modeled as a hard cap on emissions.

The EG recommends that the analysis period proposed in Section IX reflects the periods required by MCL 460.6t, which states that the filed IRPs will "provide a 5-year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations…" While the statute only requires these shorter periods, utilities frequently consider depreciation lives of 20 years or longer. Thus, the EG comments, to ensure the IRP represents all potential decisions, it would recommend a modeling period of at least 20 years, with measurements at the previously defined five-year intervals.

The Commission agrees, and Section IX has been revised to reflect this suggested revision.

The EG further comments that Section IX, Item 2 only requires modeling within Michigan and that the Commission shall require that the modeling region extend beyond the state itself, to either the northern or full MISO region. According to the EG, this will ensure that all available resources are included in the optimization. The EG comments that Section IX, Item 2, the Commission should require utilities to adequately represent the exchange of energy between Michigan and Canadian regions. The EG comments that under Section IX, Item 7, the Commission should encourage utilities to use plant-specific coal transportation prices to the greatest extent possible. Additionally, the EG suggests that utilities should rely on existing contracts for analysis wherever available. The EG suggests that the Commission clarify Item 10 of Section IX to ensure that EWR costs reflect program administrator costs only and do not include participant costs.

The Commission agrees with EG's comment on the model region and has revised Section IX to reflect the Commission's desire for the utility to model a larger region than simply its own territory or a portion of the State. While the Commission encourages the utility to model a larger region, the Commission declines to require any specific larger model region and elects to provide some level of flexibility to the utility in determining an appropriate model region for its IRP. Section IX has been updated to reflect the EG's suggestion that utilities should adequately model the exchange of energy between its territory and adjacent regions including Canada. Section IX states that coal prices should include transportation costs. The Commission agrees with the EG regarding EWR costs and has included a revision clarifying that participant costs should not be included in the IRP analysis.

Union of Concerned Scientists

The UCS also provided comments from individual members. UCS members comment that Michigan's utility planning process should account for the costs of pollution to public health, our environment, and the climate. It should value the full benefits of clean energy and EWR to our energy system, consider the equity impacts of new energy projects, and include robust public engagement so communities have a say in how they get their energy.

Other UCS members comment that it is critical for utilities to report on the emissions of their power plants, not only to understand the bigger picture of their costs and impacts on public health, but to measure and track emissions reductions as we work to transition to a clean energy future.

Other UCS members also request that the Commission consider the equity impacts of new utility investments. They comment that it is critical to assess and account for the impacts new utility investments will have on the surrounding communities, especially as the impacts of pollution from power plants disproportionately fall upon people of color and those with low incomes. Other UCS members suggest engaging substantively with communities where utility investments are proposed. When considering major investments that would affect communities, UCS members suggest that utilities and the Commission should proactively reach out to residents to hear their priorities and concerns, and take them into account when making decisions.

Finally, UCS members recommend accounting for the impact of electricity generation on public health, the environment, and the climate. According to UCS members, there are more costs to operating a power plant than simply building it and running it. The members point out that power plant emissions also affect Michiganders' health, they impact the state's environment including the Great Lakes, and they warm our climate.

The Commission agrees with UCS that IRPs should account for pollution and that IRPs should consider the full benefits of clean energy and EE to the system. To address the impact on pollution, the Commission has included, in Exhibit A, required sensitivities for aggressive levels of EWR and RE, and a required environmental policy scenario with a hard cap on carbon emissions. The Commission also agrees regarding public input and is encouraging a robust stakeholder process in the development of utility IRPs. While the Commission agrees with the concept of accounting for the costs of pollution is important, the Commission also struggles with identifying the appropriate costs to include in an IRP model and encourages UCS, utilities and stakeholders to continue to develop methods in order to ensure that the relevant costs are captured.

Charles Altman

Mr. Altman comments that the cost of externalities such as greenhouse gasses and air and water pollution should be fully factored into any decision-making.

The Commission appreciates Mr. Altman's comments, and notes that it will make its decisions in IRP cases based on each proceeding's evidentiary record and the provisions of Section 6t(8).

Jennifer Hill

Ms. Hill comments that: (1) utility companies should move beyond coal and expand and encourage EWR in their IRPs to rein in rising electricity costs and save ratepayers money; (2) IRPs should include greater investments in clean, RE, like wind and solar and make clean air and water a top priority along with reducing asthma and lung disease while saving lives; and (3) IRPs should be developed through an open and accessible process with public involvement. Ms. Hill also recommends that the UP have its own, 15 county, comprehensive integrated resource plan.

Several comments were received indicating a desire for the IRP requirements to include higher levels of EWR, RE, and clean alternatives. The Commission agrees with those comments and has endeavored to include the analysis of aggressive levels of EWR and RE as part of the requirements. In response, to Ms. Hill's comment regarding a comprehensive integrated resource plan for the UP, the Commission notes that the MAE is currently exploring planning opportunities for the UP.

PM Power Group

PM Power Group (PMPG) comments that they have had many recent discussions with citizens who are encouraging ratepayers to consider encouraging their municipality to break from the utility model, and knowing that could impact the UP much greater than Zone 7, it may need to be in the discussion.

It concerns PMPG that affordability is only on the sales side of the fence. PMPG raises questions such as job impacts of plant closures, economic impacts of distributed generation, and use of local resources. PMPG hopes the Commission's implementation of Acts 341 and 342 takes a serious look at the net present value of the energy its providing and creating, not just the cost of that MWh of energy and consider any ancillary impacts significant, especially in Zone 2.

The Commission appreciates PM Power Group's comments and encourages utilities to consider significant ancillary impacts, to the extent practical, in the IRP.

Michigan Electric and Gas Association

The Michigan Electric and Gas Association (MEGA) urges the Commission to approve the filing of the multistate IRPs to comply with Michigan requirements. Due to the varying circumstances of the other MEGA electric utilities, those with less than one million customers, MEGA requests that the Commission grant maximum flexibility under MCL 460.6t(4). This flexibility should not require prior approval of waivers, which could be a difficult and time-consuming process due to the numerous provisions of MCL 460.6t.

The Commission agrees with MEGA regarding multi-state utility IRP processes, however, the Commission may require additional information from multi-state utilities before approving the IRPs. The Commission is sympathetic to the needs of smaller utilities and intends to address those concerns, along with requests for waivers, in the IRP filing requirements docket, Case No. U-18461. The Commission also expects that the more streamlined set of scenarios and sensitivities adopted in the final planning parameters may be more accommodating for small utilities without compromising analyses that are essential to making informed decisions that benefit customers regardless of the utility's size.

EcoWorks, National Housing Trust, National Resources Defense Council, Ecology Center, Midwest Energy Efficiency Alliance, Sierra Club, Michigan Environmental Council, Michigan State Conference NAACP, and Soulardarity (Joint Group)

The Joint Group suggests that the IRP include a specific focus on low income housing, both single and multifamily, and the associated EWR potential. The Joint Group urges the Commission to ensure that the guidance also supports the ability for EWR, specifically EE measures, to compete with supply-side sources on a cost-effectiveness basis beyond the baseline 1.5% savings target. The Joint Group recommends both raising the required amount of stakeholder meetings, as well as, requiring low-income focused stakeholder meetings with dedicated outreach and specialized overview materials tied to the IRP process.

The Commission agrees with the Joint Group regarding the incorporation of high levels of EWR to be analyzed in the IRP, as well as the requirement to have EWR resources compete with supply-side resources in the IRP model. The Commission encourages a robust stakeholder process, but declines to include specific requirements in the IRP process for low-income participation, at this time. That said, the Commission does not wish to detract from the importance of EWR programs and affordability, specifically targeted at low-income customers, and encourages the utilities to continue to consider EWR programs targeted at low-income housing in EWR plans.

<u>Reply Comments</u>

Again, the Commission notes that comments similar to those already addressed previously in this order, are not specifically re-addressed in this section of the order.

David Schonberger

Mr. Schonberger replies and urges the Commission to adopt an IRP framework which explicitly mentions all applicable federal and state requirements governing the construction, operation, inspection, maintenance and decommissioning of nuclear power facilities located in Michigan. Mr. Schonberger also comments that the assumption that nuclear power plant licensees will continue operations almost indefinitely is increasingly risky.

The Commission appreciates Mr. Schonberger's comments and notes that the Commission is only including the explicit assumption that nuclear units will continue operation in the Environmental Policy Scenario, where emission-free generation may provide value to the system.

Laura Chappelle

Ms. Chappelle's reply comments focus only on Scenario 2 of the Strawman Proposal. Ms. Chappelle states that the Strawman Proposal correctly includes non-utility-owned existing resources that should be included in the modeling process. Ms. Chapelle also makes the following suggested changes to the currently-drafted fifth bullet: (1) Replace the word "or" with "and" in the introductory paragraph: "Prior to *and* during the modeling process, the utilities shall take into account resources that include . . ." This change will ensure that this important aspect of including the consideration of existing resources occurs prior to – *and in* – the modeling process; (2) include all QFs and not just those 20 MW and under; (3) adopt the recommendations made by Wolverine and the EIBC that greater specificity and/or the inclusion of specific planning parameters or a more definitive list of existing and/or proposed resources not owned by the petitioning utility should be included in the sensitivities guiding utility modeling in this area. Ms. Chappelle agrees that specified detail currently included in the draft IRP Filing Requirements be included in the Strawman Proposal. Ms. Chappelle also agrees with the EIBC that several areas should be included as sensitivities for modeling.

Ms. Chappelle also replies to several of Consumers' recommendations to account for Large Electric Users' assumed reduction of load due to the customers' use of CHP, batteries, and/or behind the meter generation in the utility's base load forecast instead of through a separate forecasted sensitivity should be rejected. Ms. Chappelle comments that customers' decisions to develop CHP or behind-the-meter resources should not be projected by the utility outside of the IRP model because: (1) those decisions will be made in light of the cost of utility services that are determined by the utility decisions to be modeled; (2) the IRP process should be optimizing resources based on cost to society, rather than value to the utility, so these types of load-reducing resources should be considered in competition with utility resources on the basis of direct comparison in the IRP; and (3) although the company refers to these load-reducing options as a way to offset high electric rates, their use should also be properly modeled to ensure that the IRP – which is a need-based document, properly reflects the amount of energy and capacity for which the utility should be planning.

Ms. Chappelle also agrees that ABATE's recommendations regarding data requirements" should be adopted in full.

Responsive to Ms. Chappelle's comments, revisions were made to the Emerging Technologies Scenario regarding the consideration of specific resource prior to and during the modeling process, as well as a requirement to assume that existing PURPA contracts be renewed, including a provision for the incorporation of larger qualifying facilities. The Commission agrees with Ms. Chappelle regarding rejecting the proposal to incorporate the assumed load reductions from the previous large electric users sensitivity into the base forecast for scenario and as previously discussed, was removed by the Commission from the scenario altogether. The Commission appreciates Ms. Chappelle's comments regarding the consideration of transmission options and her support for specific data requirements and the Commission intends to be responsive to those issues in Case No. U-18461.

Association of Businesses Advocating Tariff Equity

ABATE replies that the Commission should require, at a minimum, that utilities incorporate consistent studies and forecasts in their IRPs. According to ABATE, this will establish a baseline and allow for uniform comparisons. If nothing else, ABATE continues, it will prevent utilities—and those offering alternative plans—from cherry-picking studies and forecasts which justify their proposed plans.

ABATE further replies that the Commission must establish the modeling scenarios and assumptions each electric utility should include *in addition to* the utilities' own scenarios and assumptions. ABATE suggests that the utilities are free to supplement their IRPs however they choose, but the Commission should require a uniform set of sensitivities for all IRPs.

ABATE disagrees with MEGA's characterization of Section 6t(4) of Act 341. ABATE asserts that this provision of the law provides the Commission with the *option* to adopt separate filing requirements for smaller utilities. According to MEGA, however, this language expresses a clear legislative intent that the Commission should provide more flexibility for both multistate and smaller rate-regulated utilities. ABATE replies that this is a stretch. If the Legislature truly intended for there to be two sets of filing requirements, it would have simply mandated that the Commission adopt less stringent standards for smaller utilities. Granted, the Commission may find good cause to allow some leeway for smaller utilities. ABATE would caution, however, that the Commission refrain from adopting an across-the-board approach for smaller utilities.

The Commission agrees with ABATE that the required modeling scenarios and assumptions each electric utility should include are *in addition to* the utilities' own scenarios and assumptions and Exhibit A has been updated to clarify this point. While the Commission agrees with ABATE that the Commission has the option to adopt separate filing requirements for smaller utilities, the Commission is sympathetic to the needs of smaller utilities and intends to address the issue in Case No. U-18461.

Consumers Energy Company

With regard to the load projection sensitivities, Consumers notes that the Staff provided an additional sensitivity for all three scenarios indicating a minimum spread of 3% between the low load growth sensitivity and the high growth sensitivity. For clarification, Consumers replies, it is assumed that the 3% spread is intended to be an equivalent split between the high and low percent increase and decrease, respectively. Consumers replies that it can be beneficial to see the effects of high and low load growth compared to the BAU base case load growth; however, to provide value, the load growth sensitivities performed must have the potential to occur within the scenario described. Consumers comments that in the BAU scenario, it is possible that load growth will be above or below the current projection, but not to the level recommended by the Staff. Achieving the level of load growth recommended by Staff, Consumers states, would require extreme economic conditions that are very unlikely to occur for short periods of time, let alone be the average over a 15-year period. For example, to increase the load growth from its current outlook, Consumers states that it would require 10% growth in Michigan's economy. Consumers comments that the 3% spread is not needed in each scenario and would only be appropriate at a lower spread in the BAU Scenario.

The Commission has not adopted the Staff's recommended 3% spread, making this reply comment moot.

Consumers also comments on the Large Electric Users Sensitivity. Consumers replies that the statement, "this could result in up to a 25% reduction in total load for the utility" seems unreasonable even in an Emerging Technologies Scenario. Consumers continues, a 25% reduction in total load would require a 90% reduction in Consumers' primary industrial load. Consumers further provides, the 25% appears to be arbitrary and no support has been provided to justify the reasonableness of this projection. The company recommends not including this statement because it would result in an unrealistic sensitivity.

The Commission removed the requirement for the Large Electric Users sensitivity.

Consumers agrees with other commenters requesting the carbon reductions be based on a cap methodology versus a price methodology.

Consumers comments on the IRP planning period by noting that many commenters recommended extending the IRP planning period to at least 20 years. Consumers points out that the planning period required by Section 6t(3) of Act 341 indicates 5-year intervals that project over a 15-year horizon. According to Consumers, requiring at least 20 years would not be consistent with the requirements of the statute and would provide little additional value.

The Commission disagrees. The long-term nature of utility investments warrants a net present value analysis over a longer time period; one closer to the useful lives of the assets considered in the IRP expansion planning models.

The UCS recommends a full accounting of certain air emissions, as well as projected production of wastewater effluent, coal combustion residues, and other byproducts viewed as having potential impacts to the public health over the planning period, and be provided on an annual basis. Consumers finds that this request for annual information is redundant to reporting requirements currently required by the EPA and or the MDEQ.

The Commission intends to address reporting requirements in Case No. U-18461.

Consumers replies that some parties filed comments requesting that utilities develop a probability ranking of which projects in the MISO Interconnection Queue would become operational. Consumers believes that this would require significant effort and yield limited value.

The Commission agrees, and therefore, no specific requirement to include a probability ranking of the likelihood of the completion of projects in the MISO Interconnection Queue has been included.

Consumers also replies to a recommendation in comments provided by ELPC, Sierra Club, NRDC, UCS, Earthjustice, Ecology Center, and 5 Lakes Energy to emphasize the need to evaluate an optimal retirement. Consumers states that modeling limitations make determining an "optimal" retirement date difficult and time consuming and would provide only the economic viewpoint. An IRP, according to Consumers, must consider impacts to employees, communities, etc. when considering retirement of existing generation. Consumers believes it would be inappropriate to rely on the production cost model to identify this data given the need for additional consideration. Consumers also believes that it is inappropriate to consider unavoidable sunk costs but it is appropriate to consider ongoing avoidable investments. Consumers replies that the Staff's proposed scenarios and sensitivities, as modified by the comments provided by the company on October 6, 2017 in this proceeding, are appropriate and will result in the best action plan given all necessary considerations.

The Commission is sensitive to the time-consuming nature of IRP modeling and understands that many issues must be considered before making a decision regarding unit retirements, however, the Commission believes that under certain circumstances, valuable insights may be gained by allowing the model to retire units based on economics. As previously stated, in Exhibit A, the Commission has clarified the retirement assumptions to be used for each of the required scenarios.

Consumers replies to MEC's recommendation to adjust Sensitivity 5 of the BAU case to focus solely on RE and suggests utilities be required to model a 100% increase in renewables between 2021 and 2030. Consumers replies that it is assumed that this increase is intended to model a 30% renewable portfolio standard (RPS). If this is an accepted change, clarification of its application is necessary.

Consumers agrees that it is appropriate to include a retail open access (ROA) sensitivity in IRP modeling; however, it is not appropriate to include ROA sensitivity at a level that considers all customers in the queue that could switch to an alternative energy supplier (AES). The company supports a sensitivity that evaluates ROA returning load in light of the state reliability mechanism (SRM) and as suggested by the Commission in the Palisades securitization proceeding, Case No. U-18250. Additionally, Consumers notes that a low load projection would provide the analysis needed to understand the effects of increased ROA customers.

The Commission agrees with Consumers regarding the incorporation of potential impacts resulting from changes in ROA load and has incorporated revisions reflecting Consumers' comments in Exhibit A.

Consumers also comments in reply that the three scenarios proposed by the Staff are relatively similar, containing the same assumptions and sensitivities. For example, the BAU Scenario does not assume a robust economy but low natural gas price projections, which is identical to what is assumed for the Environmental Policy Scenario. Likewise, Consumers replies that the Environmental Policy Scenario contains increased EV usage and reduced load due to large electric users driven to self-generating resources that are also included in the Emerging Technologies Scenario. Consumers notes that there is a level of redundancy in the assumptions and sensitivities that are proposed by the Staff. Consumers believes that its suggestions in its initial comments in this proceeding help to reduce the level of redundancy.

While the Commission agrees with Consumers that the underlying natural gas prices are consistent across the three scenarios applicable to the Lower Peninsula, the Commission has done so on purpose. Different utilities and different stakeholders may hold widely differing views regarding how to appropriately quantify the impacts from qualitative descriptors, such as a robust economy, or the changes expected to load forecasts and load shapes from increased EV usage. The Commission has elected to streamline the scenarios, to the extent possible, and has elected to incorporate a broad range for some key variables, such as the natural gas price, in the required sensitivity analyses. Utilizing consistent load forecasts and natural gas prices in some of the required scenarios should reduce the number of disagreements among stakeholders regarding the somewhat subjective nature of the impact of emerging technologies or the impact of environmental policy, on those key assumptions, at least for the required scenarios. The Commission expects that the utilities will develop their scenarios and sensitivities in addition to the requirements outlined in Exhibit A, and reiterates that the utilities may design their own additional scenarios and sensitivities, with differing assumptions, as they see fit.

Consumers also agrees with DTE Electric, in that any party wishing to view proprietary data that is designated by the third-party vendor needs to first purchase a license at their expense.

DTE Electric Company

DTE Electric replies that for purposes of IRP modeling, forecasted EE savings should be aggregated into hourly units, coincident with hourly load forecasts, with indicative estimates of efficiency cost and savings on an hourly basis. It is this aggregation and forecast of EE, to be acquired on an hourly basis that allows EWR to be modeled as a resource in an IRP for planning purposes.

The Commission agrees, and Exhibit A, section X has been updated to reflect this revision.

DTE Electric replies that the current list of federal and state environmental rules and regulations is current and comprehensive. The Act 341 requirements will need to allow for the consistent changes that occur to rules and regulations. DTE Electric comments that MEPA, as noted by several stakeholders, is more of an over-arching law than an environmental regulation.

DTE Electric agrees with other stakeholders that there are too many sensitivities, which will overly complicate and make the analysis process unnecessarily lengthy, and require significant resources. Due to the redundancy between the narratives of the scenarios and requested sensitivities, DTE Electric suggests, some sensitivities be eliminated. As an example, DTE Electric provides, the transportation energy and large electric users do not need to be separate sensitives because they are captured in the high load projection sensitivity. DTE Electric also comments that there were stakeholder comments in favor of additional sensitivities that would provide little or no value. For example, a sensitivity on decreased income tax rate is not needed, the production tax credits for wind are expiring soon and the solar income tax credit will only be at 10%. Additionally, sensitivities for EWR and lower battery storage cost curves will be captured in the second Scenario - Emerging Technology. The scenarios identified and a pared-down list of sensitivities in the current strawman are sufficient to provide a robust analysis.

The Commission has endeavored to reduce the amount of sensitivities required and the changes are reflected in Exhibit A.

American Council for an Energy Efficient Economy

The American Council for an Energy Efficient Economy (ACEEE) replies that the assumption of 1.5% EWR annual savings in the BAU base case is reasonable. DTE Electric and Consumers have easily exceeded the 1% annual savings target every year that target has been in effect, even while often having curtailed some programs at mid-year due to the 2% spending cap. ACEEE comments that that spending cap has now been eliminated, allowing a more complete response to the robust customer demand for participation.

ACEEE replies that other leading states do provide an appropriate benchmark for what Michigan utilities could achieve. According to ACEEE, Michigan should be in a better position than those other states that have already captured far more efficiency improvements over the years, yet the average annual projected savings across those six states for the 2016-2020 time period is nearly 2.0%. According to ACEEE, experience in other leading states indicates that a 1.5% annual savings assumption for the BAU base case analysis should be eminently reasonable and assuming a customer incentive of 100% of incremental measure costs is entirely appropriate for assessing EE achievable potential.

Alliance to Halt Fermi 3

The Alliance to Halt Fermi 3 (ATHF3) strongly disagrees with DTE Electric's assertion that the draft inventory list is "comprehensive." ATHF3 comments that its inventory of concerns are summarized in an attached appendix, emphasizing the Atomic Energy Act and National Environmental Policy Act as significant federal laws with a broad environmental compliance scope, for new and existing facilities, affecting and applicable to electric utilities in this state. In addition, ATHF3 endorses the relevant comments submitted by MEC pertaining to the Strawman's omission of MEPA requirements. ATHF3 states that no matter the logic or course of reasoning, at the end of the day, imprudent omissions will inevitably lead to imprudent actions and future outcomes.

As previously stated, the Commission has elected to incorporate MEPA into the environmental regulations section of Exhibit A. The Commission declines to incorporate the Atomic Energy Act at this time, but notes that its lack of inclusion in the IRP requirements does not detract from any entity’s requirements to comply with the Atomic Energy Act.

Midwest Energy Efficiency Alliance

The MEEA supports a process that incorporates customer feedback, in addition to that of intervenors, to keep the utilities apprised of customer concerns regarding the continued delivery of cost-effective and reliable energy resources. MEEA comments that there are many helpful examples throughout the Midwest. For instance, in Indiana, a customer or interested party may comment on an IRP submitted to the commission. According to MEEA, Indiana also affords flexibility on the part of utilities to hold advisory group (stakeholder) meetings, but they also provide an opportunity for public participation in a timely manner that may affect the outcome of the utility resource planning efforts. MEEA also provides that in Minnesota, parties and other interested persons have until [a date] to review and comment upon the resource plan filings…[which] may include proposed alternative resource plans. These practices appear to be consistent in principle with the Section 6t(1) Act 341directive that "[b]efore issuing the final modeling scenarios and assumptions each electric utility should include in developing its integrated resource plan, receive written comments and hold hearings to solicit public input regarding the proposed modeling scenarios and assumptions." MEEA believes that the most important component to the stakeholder process going forward is that it be clearly defined to ensure all involved are aware of the requirements and expectations in addressing concerns and developing a successful IRP.

The Commission agrees, and as previously stated, encourages robust stakeholder engagement in the development of utility IRPs.

Soulardarity

Soulardarity replies that strong stakeholder engagement process should have specific focus on demographics most impacted by energy decisions – particularly low-income communities, communities of color impacted by environmental racism, rural communities harmed by resource extraction and energy poverty, and other impacted communities. Soulardarity also comments that a strong stakeholder engagement should provide education to stakeholders to understand how the

IRP process works and how to make impactful comments by working through community organizations that work directly with impacted communities to ensure culturally appropriate and effective engagement. Soulardarity reemphasizes its other positions regarding the stakeholder process and engagement.

Union of Concerned Scientists, Michigan Environmental Council, Sierra Club, 5 Lakes Energy, Earthjustice, Environmental Law & Policy Center, Natural Resources Defense Council, Ecology Center, Great Lakes Renewable Energy Association (Joint Group)

The Joint Group replies that they do not agree with either Consumers' or DTE Electric's rationale for proposing to lower the assumed levels of EWR in the scenarios and sensitivities set forth by the Staff. They comment that utilities are not precluded from running additional scenarios/sensitivities of their choosing, including with lower levels of EWR.

The Joint Group also points out that both DTE Electric and Consumers raise concerns that the low growth rate sensitivities proposed by the Commission will not result in meaningfully distinct results from the BAU because BAU load growth projections are already close to zero. Although agreeing with that position, the joint commenters believe a preferable solution is to modify the sensitivity description so that negative load growth can be modeled in the low growth sensitivity.

The Commission notes that the aggressive EWR sensitivity in the BAU scenario, which ramps up to 2.5% annually over a four-year period and is held at high levels through the study period will likely result in measurable negative load growth, therefore the Commission has elected not to include a separate low-load growth sensitivity.

The joint comments further provide that both DTE Electric and Consumers suggest that retirements of existing generating units should be assumed inputs rather than allowing the model to select retirements through its optimization process. The joint comments disagree with this approach as it is contrary to the goal of the modeling exercise to determine the most reasonable and prudent plan for meeting electricity demand. The group believes that allowing a utility to limit its consideration of unit retirements to those that are hardwired into the modeling severely limits the model's ability to find the optimal mix of resources. In most scenarios and sensitivities, coal retirements should be considered; 1) based on retirement commitments, and 2) on the optimal resource mix determined by the modeling exercise.

The Commission does not disagree, but has elected to allow for flexibility in modeling the retirement of the utility's owned units in the BAU Scenario, and has retained provisions for requiring that the model be allowed to select retirements for the utility's coal units based on economics in specific instances in the Emerging Technologies Scenario and the Environmental Policy Scenario, as specified in Exhibit A.

The joint comments also state that the Commission should require the utilities to provide, at a minimum: (1) the name of any model(s) used; (2) copies of the corresponding user manuals; (3) a description of each output report available; (4) modeling inputs and outputs in a searchable format; and (5) all work papers and supporting document.

The Commission finds this suggestion reasonable, however, declines to address data reporting requirements at this time, as similar issues will be addressed in Case No. U-18461.

The joint comments agree with Consumers' comment that the IRP parameters should explicitly include language clarifying the Commission's authority to request additional information from multistate utilities if necessary as part of its evaluation and determination of whether to approve an IRP pursuant to section 4 of Act 341.

As previously stated, the Commission agrees.

In response to Consumers' and DTE Electric's suggestion to not increase natural gas prices by 300%, but limiting it to a 100% increase, the joint comments would agree that a 200% increase is likely sufficient to demonstrate a high natural gas price for modeling purposes. They also agree with the suggestion to remove the sensitivity using a 50% decrease.

As previously stated, the Commission agrees.

The joint comments disagree with DTE Electric's suggestion to use its own natural gas fuel price forecasts in Commission-mandated scenarios and sensitivities. DTE Electric is welcome to put forth additional scenarios and sensitivities with independent natural gas fuel price forecasts, but opening the door for each utility to submit modeling premised on different natural gas price forecasts lends itself to confusion and adds difficulty in the Commission's effort to identify the most reasonable and prudent plan for meeting future electricity needs.

As previously stated, the Commission agrees.

The joint comments state that the Commission should remove unnecessary assumptions on what conditions are driving each of the scenarios. According to the joint comments, the costs of emerging technologies (Scenario 2) can drop in the absence of a "robust economy". In the same vein, utilities should not be allowed to eliminate sensitivities based on their assumptions regarding economic conditions.

As previously stated, the Commission agrees.

The joint comments disagree with Consumers' recommendation to eliminate the 35% reduction in costs for emerging technologies and limiting the reduction in costs to only those recognized in the referenced studies. This proposal should be rejected because it undermines the entire purpose of the scenario of evaluating the potential for cost reduction beyond those currently projected.

As previously stated, the Commission agrees.

The Joint Group also notes that the MDEQ's submitted regulatory timeline that identifies the dates of various environmental regulations that apply to coal-fired power plants, identified EPA's April 2017 purported administrative stay of the Steam Electric Effluent Guidelines (SEEG), also known as the power plant Effluent Limitation Guidelines (ELGs). The Joint Group states that the administrative stay, however, was lifted by EPA's September 18, 2017 rulemaking postponing certain SEEG compliance deadlines. Through that rulemaking, the EPA has established an earliest compliance date for SEEG of November 1, 2020, while the latest compliance date of December 31, 2023 remains in place. Those dates should be reflected in the environmental regulatory timeline for the IRPs.

The Commission agrees, and the environmental regulatory timeline has been updated to include revised dates for SEEG compliance in Exhibit A.

Public Hearings

As required by statute, the Commission held public hearings across the state to reach out and gather input on the IRP process and parameters. The Commission is pleased with the level of participation in the public hearings and expresses thanks to all who participated. The Commission finds the comments received during the public hearings valuable and has incorporated several revisions to Exhibit A based upon those comments. Again, the Commission will not address any comments in this section that have already been addressed earlier in this Order.

First Public Hearing

On September 6, 2017, the first community outreach hearing was held at Schoolcraft College in Livonia, Michigan. Administrative Law Judge Dennis W. Mack (ALJ Mack) presided over the proceedings with Commissioner Rachael A. Eubanks, and Bonnie Janssen from the Staff providing information on Act 341 and the framework for establishing the parameters and assumptions for the IRP process. Following Ms. Janssen's presentation, ALJ Mack opened the forum for public comment. The following is a summary of those public comments.

Dr. Martin Kushler

Dr. Kushler is a Senior Fellow with ACEEE. Dr. Kushler provided that ACEEE finds the EWR assumption of a 1.5 % annual savings, as a base case in the BAU scenario, reasonable. Dr. Kushler stated that the most recent National State Energy Efficiency Scorecard demonstrated that a total of 6 states are planning to require a 2% EWR or more savings a year and therefore finds the Michigan's proposed 1.5% requirement readily achievable. ACEEE also supports the modeling of additional potential EE resources beyond the base case scenario, and also examining more aggressive assumptions in EE achievements. ACEEE is also pleased with the stated goal that 35% electric needs by 2025 being meet by a combination of EWR and RE. ACEEE avers that the EWR portion should be based on the EWR measures installed that have a useful lifetime covering 2025 or beyond and not simply on the addition of the annual incremental savings achieved since 2009.

Joanna Lewis

Ms. Lewis is the Program Administrator for the Michigan Conservative Energy Forum (MCEF). The MCEF believes that residential ratepayers and small businesses are demanding the option to purchase RE and that "Green Pricing" programs need to be valued to reflect all of their benefits and not simply priced by adding a premium cost above and beyond traditional rates. MCEF further believes that residential and small businesses are not adequately included early in the IRP process. Finally, MCEF believes that the Commission should ensure a fair and competitive market that includes independent power producers to drive innovation and help lower everyone's energy bill.

James M. Rine

Mr. Rine, speaking on his own behalf, stresses that the objective of 35% electric generation from EWR and RE by 2025 with a goal of 50% by 2035 should be the bare minimum.

Kindra Weid

Ms. Weid is the Coalition Coordinator with Michigan Air Michigan Health, which is a coalition of health professionals that work to improve outdoor air quality. Ms. Weid encourages the Commission to require utilities to consider health and environmental impact in their IRPs.

Mara Herman

Ms. Herman is a Health Outreach Coordinator at the Ecology Center, but is commenting on her own behalf. Ms. Herman's comments also direct the Commission to require health and environmental impacts in utility IRPs.

Regina Strong

Ms. Strong is the Director of the Michigan Beyond Coal Campaign for the Sierra Club. Ms. Strong comments that when utilities are required to retire coal plants that there should be an equitable policy for that transition with coal plant employees and the communities where the plants are located. Ms. Strong encourages an open and accessible IRP process with a visible and active role for the public. Ms. Strong further comments that clean RE investment and EWR should be an IRP priority along with reducing health risks associated with coal-fired plants.

Cecilia Trudeau

Ms. Trudeau, commenting on her own behalf, encourages the Commission to give health decisions the attention they deserve. Ms. Trudeau comments that she has witnessed children and their families suffer illness caused or exacerbated from air pollution and that increased RE and EWR should be a priority.

Keith W. Cooley

Mr. Cooley, speaking on his own behalf, comments that for both health and economic reasons the Commission should encourage more RE and EWR.

Noah Purcell

Mr. Purcell is encouraged by the measures undertaken in the study guiding the Strawman Proposal to identify EWR opportunities for low income housing. Mr. Purcell encourages even greater focus on this EWR potential and suggest that a low-income specific study should be part of the IRP process.

David Hurwitz-Goodman

Mr. Hurwitz-Goodman comments on his own behalf that he has witnessed that the poor residents of Detroit, especially those of color, bear the brunt of dirty energy production, while paying a disproportional share of the cost of production. Mr. Hurwitz-Goodman comments that low-income individuals and families would benefit greatly from RE investment and EWR measures.

Clay Carpenter

Mr. Carpenter comments on behalf of the Clean Water Action/Clean Water Fund of Michigan and on behalf of several of its members. Mr. Carpenter commented that it is important for Michigan to transition away from coal to clean, RE produced in Michigan. Mr. Carpenter comments that power plants emit dangerous levels of mercury, sulfur, carbon, and arsenic and are among the biggest polluters of the Great Lakes.

Brother Thomas Zerafa

Brother Zerafa comments that he works with many elderly people in the southwest Detroit and sees a rate of asthma in that area. Brother Zerafa also believes that southwest Detroit pays an unfair share of utility services.

Second Public Hearing

On September 13, 2017, the Commission held its second public hearing at the L.V. Eberhard Center in Grand Rapids. Administrative Law Judge Suzanne D. Sonneborn (ALJ Sonneborn) presided over the proceedings. Commission Chairman Sally A. Talberg provided opening remarks to the attendees. Chairman Talberg provided context to the new comprehensive energy legislation and goals for the IRP process. Paul Proudfoot, Director of the Commission's Electric Reliability Division, provided information regarding the importance of establishing modeling scenarios that utilities will be required to run when creating their IRP plans. ALJ Sonneborn then opened the forum for public comment with 12 individuals, either independently or as an organization representative, taking advantage of the opportunity. The following comments were provided at the hearing.

John McGarry

Mr. McGarry comments that the Commission should adopt a social cost of carbon in the utility IRP process. Mr. McGarry stated that Colorado has adopted a similar provision for its utilities and has set a social cost of carbon at $43 a ton in 2022 and escalates to $69 a ton in 2050. Mr. Garry also comments that Michigan should continue to follow the Clean Power Plan as the net benefits outweigh the costs.

The Environmental Scenario includes a hard cap on the amount of emissions as opposed to a price on carbon, however the Commission appreciates receiving specific feedback for a potential range of the future social cost of carbon.

Selina Bokare

Ms. Bokare is the Assistant Coordinator with Michigan Air Michigan Home. Ms. Bokare comments that utilities should make clean air and water their top priority. Ms. Bokare comments that expanding clean RE and EE will help protect the health of Michigan's most vulnerable populations.

Allison Sutter

Ms. Sutter is the new Sustainability Manager for the City of Grand Rapids. Ms. Sutter comments that the City of Grand Rapid's goal is to be 100% RE by 2025 and to reduce greenhouse gases 25% below 2009 levels by 2021. Ms. Sutter hopes that Michigan will become best in class when it comes to RE and looks forward to a continued partnership with the Commission.

David Die

Mr. Die recommends that the Commission work to expand awareness about the green certification pathway in the Michigan Building Code. Mr. Die recommends removing utility rebates and create performance-based rebates similar to Consumer's commercial building rebates. Mr. Die also supports more clean RE.

James Clift

Mr. Clift is the Policy Director for MEC. Mr. Clift spoke on behalf of the MEC and presented various comments related to MEC's positions for the IRP process. Mr. Clift also submitted substantially similar comments in this docket, which have already been addressed.

Ken Pierce

Mr. Pierce comments that any IRP process must be undertaken in the context of climate change. Mr. Pierce suggests that the Commission place a price on carbon to deal with externalities resulting from carbon emissions.

The Commission appreciates Mr. Pierce's comment and notes that several others commented regarding placing a price on carbon, but as previously stated, the Commission has elected to require the utilities to model a hard cap on emissions in the Environmental Scenario as opposed to placing a price on carbon.

Joanna Lewis

Ms. Lewis presented similar comments on behalf of the MCEF that she made at the Livonia public hearing.

Keith den Hollander

Mr. den Hollander, speaking on behalf of the Christian Coalition of Michigan, comments that various coal plants around the world are set for closure. Mr. den Hollander also notes that utilities are looking to or already have replaced coal generated electricity with natural gas plants. Mr. den Hollander recommends planning to include generation from sources with more fixed costs, such as wind, solar, hydropower, and biomass. He comments that demand for natural gas will certainly raise prices for that commodity and thus raise electric prices if too much reliance is placed on that source for Michigan's electricity needs.

Regina Strong

Ms. Strong makes comments on behalf of the Sierra Club. Ms. Strong made similar comments at the Livonia hearing, which have already been addressed.

Dan Scripps

Mr. Scripps is the Vice President of EIBC, and comments on that organization's behalf. EIBC filed extensive comments in this docket covering the same or substantially similar areas related to the IRP, which have been addressed previously.

Nick Dreher

Mr. Dreher is the Policy Manager for Midwest Energy Efficiency Alliance. Mr. Dreher also represents the Low- Income Energy Working Group and comments that the low-income housing stock is underutilized source for EE measures. Mr. Dreher comments that the low- income community members face a disproportionate burden when it comes to their energy costs and recommends the Commission advance opportunities for EWR savings to these customers.

Mr. Dreher also recommends that the Commission should support energy efficient measures to compete with other generation sources on a cost effective mix basis beyond the 1.5% level in the Strawman Proposal.

Kathy M.

Kathy M. expressed her concern for tree removal to make room for more buildings. She hopes that the Commission will consider the destruction of these "carbon catchers" in the planning process.

<u>Third Public Hearing</u>

On September 9, 2017, the Commission held its third and final public hearing at Northern Michigan University in Marquette, Michigan. Administrative Law Judge Sharon L. Feldman (ALJ Feldman) presided over the proceedings. Commissioner Norman J. Saari provided opening remarks to those in attendance regarding the importance of IRP to prepare for Michigan's energy future. Bonnie Janssen from the Staff gave a brief presentation that included an overview of the

IRP process and proposed modeling scenarios. Ms. Janssen also answered several questions from the audience. ALJ Feldman then opened the floor for comments.

James Haun

Mr. Haun's comments on the destruction of forest habitat associated with wind turbines in the Huron Mountains. Mr. Haun considers the area a special place and does not want to see it destroyed.

Gary Talarico

Mr. Talarico comments on his own behalf and believes that the entire UP should be covered by one IRP. He claims that it does not make sense in the UP to have each utility to serving that area to have its own IRP.

Dan Scripps

Mr. Scripps comments on behalf of the EIBC and makes several points specific to the UP. Mr. Scripps comments that the IRP process in the UP should carefully review EWR opportunities. Mr. Scripps further comments that UP IRP modeling should include non-utility resources with a specific emphasis on expanding PURPA contracts. Mr. Scripps also comments that demand response from the large electric users should also be carefully reviewed in the IRP process. The EIBC also believes that the opportunity for growth in distributed solar as resource may be even greater in the IRP process.

While the Commission has not elected to require assumptions regarding expanding PURPA contracts at this time, the Commission has added a requirement to assume that existing PURPA contracts are renewed.

Catherine Andrews

Ms. Andrews is concerned with the designation of some small generating facilities as biomass plants. She comments that one plant, in particular, has had two EPA Clean Air Act violations and that plants burns tire chips and railroad ties.

Fran Whitman

Ms. Whitman comments also relate to similar problems with biomass plants near L'Anse. Ms. Whitman believes that biomass plants have a negative effect on clean air, clean water, and clean living that is essential to the quality of life in the area.

Douglas Jester

Mr. Jester is a partner with 5 Lakes Energy and comments that the Commission should consider co-optimization of transmission and generation for IRP in the UP. Mr. Jester further comments that it is very important for UP utilities to evaluate IRP plans with and without their respective largest customers. Mr. Jester comments that many of the large customers that represent a majority of the load for a utility and are commodity interests subject to the volatility of the markets. Evaluating scenarios with and without this load, Mr. Jester suggests, would assist the Commission greatly in its ability to make related decisions.

The Commission appreciates Mr. Jester's comments and notes that MAE is exploring options to address planning issues which are specific to the UP.

Jennifer Hill

Ms. Hill comments that the future of energy will be much different in the UP. Ms. Hill recommends incentivizing EWR in the region. Ms. Hill is also pleased to see that the UP's unique situation was represented in the scenarios and sensitivities.

David Gard

Mr. Gard comments on behalf of MEECA. MEECA filed extensive comments in the docket and Mr. Gard's comments are substantially similar to those previously filed.

Joanna Lewis

Ms. Lewis comments on behalf of the MCEF. Ms. Lewis previously commented at both the Livonia and Grand Rapids hearings and her comments are substantially the same has those previously offered.

The Commission is extremely thankful to all utilities, businesses, advocacy groups, and other interested persons that contributed their time and energy to bring forth their perspectives on the IRP planning process and the future direction of Michigan's electrical energy outlook. In addition to the comments received and pursuant to Section 6t(1) of Act 341, the Commission also solicited input from the MDEQ and MAE on topics including, but not limited to, identifying existing and proposed environmental regulations, laws, and rules, as well as identifying required planning reserve margins and local clearing requirements in areas of this state. The Staff coordinated with these agencies to ensure information was submitted in a timely manner for consideration by the Commission.

<u>Discussion</u>

The Commission carefully reviewed all the comments received and the input received from the Staff's collaborative efforts along with the written comments received in the docket and the comments made at the public hearings discussed throughout this order. After consideration of all the comments, Exhibit A includes a revised document titled, Michigan Integrated Resource Parameters Planning Parameters (MIRPP), dated November 21, 2017, which includes several substantive changes compared to the initial draft that was released for comments in this docket.

In this next section the Commission summarizes the substantive changes incorporated into Exhibit A.

I. Table of Contents

Appendix E was added to the Table of Contents. The document was submitted by the MDEQ and illustrates the regulatory timeline of environmental regulations, law, and rules discussed in section VI.

II. Executive Summary

The executive summary section was revised to reflect the release of the Demand Response Potential Study. In response to ABATE's comments, the executive summary also clarifies that the final scenarios and sensitivities in the planning parameters are the minimum requirements to be incorporated into utility IRP filings and acknowledges that utilities may include additional scenarios and/or sensitivities. As ABATE suggests, it is beneficial to have a robust analysis presenting several varying possible futures because the future is unknown.

III. Background

The Commission made no changes to this section.

IV. Energy Waste Reduction Potential Study

The Commission moved the description of the EWR potential study to an introductory paragraph to this section. The change was made to better organize the information. General additions were also added to this section to allow for a better understanding of the study and results.

V. Demand Response Potential Study

In accordance with the October 5 notice requesting comments on the DR Study, Consumers, DTE Electric, and ABATE filed initial comments. Neither utility makes specific comments in relation to the IRP process but reserves the right to address DR in their IRP filings. ABATE comments that industrial and large commercial customers can play a significant role in alleviating some of the stresses on the electrical grid and that the Commission should remove any unnecessary barriers to DR markets. ABATE suggests several options that the Commission should consider to increase DR options.

Although the Commission is receptive to the positions set forth in ABATE's comments, the Commission agrees with the utilities that this proceeding is not the forum to address those items. In Case No. U-18369, the Commission recently addressed the regulatory approach for addressing DR program review and cost recovery. Thus, this section and subsections were only updated for clarification purposes as well as to provide further information on the results of the study.

VI. State and Federal Environmental Regulations, Laws and Rules

1. Steam Electric Effluent Guidelines

The change in the guideline compliance information was written by the MDEQ based on reply comments received from the group of environmental advocates. The regulatory timeline in Appendix E was also updated to reflect this change.

2. Michigan Environmental Protection Act

Several commenters expresse the desire to include the MEPA as part of the State Rules and Laws subsection, and the Commission included language describing this law.

VII. Planning Reserve Margins and Local Clearing Requirements

Clarifications were added to this section to further explain MISO's process for modeling the PRM and the LRR. These clarifications were added based on comments submitted by DTE Electric. Additionally, this section has been modified to reflect the Commission's actions taken to implement reliability requirements included in Section 6w of Act 341 subsequent to the submission of the Strawman Proposal in the docket.

VIII. Modeling Scenarios, Sensitivities and Assumptions

Comments were received from Consumers and MEC regarding the Commission's need to request additional information from multistate utilities prior to approving their IRP, should it be necessary. The Commission agrees there should be clarification and therefore added the statement concerning the request of information pursuant to Section 6t(4) of Act 341.

As discussed by the Commission previously, several changes were made to the descriptions in the scenarios and sensitivities for clarification purposes, as well as to alleviate some perceived internal discrepancies. Also, as previously discussed, key variables such as the natural gas price forecast and the demand and energy forecast have been purposefully aligned in certain scenarios, while providing for a considerable range of future values of each of those variables to be evaluated in sensitivity analyses. Both Consumers and DTE Electric comment that the overall magnitude of the number of scenarios and sensitivities should be reduced. As previously discussed throughout this order, the Commission has endeavored to reduce the burden of the required modeling scenarios and sensitivities and in addition to streamlining some key assumptions across certain scenarios, the Commission has also reduced the required number of sensitivities. A summary of the changes made to each scenario is included below.

1. Scenario 1 - Business as Usual

Michigan Biomass comments that existing PURPA contracts should be assumed to be renewed under the BAU Scenario. The Commission agrees with that comment and therefore added it to the scenario.

2. Business as Usual Sensitivities

Multiple utilities suggest in comments that natural gas fuel price projections increase by 150% to 200% in the high gas price sensitivity. Environmental groups suggested that 200% would be acceptable. Given the comments filed, and as previously discussed, the Commission finds it appropriate for the high gas price sensitivity to increase projections to 200% above the BAU natural gas fuel price projections at the end of the study period. DTE Electric commented that they would like a transition period from the current natural gas price to the projected natural gas prices. The Commission agrees with this general approach and has added specific language to allow the increased natural gas fuel prices to grow from current to 200% above at the end of the study period. While the Commission recognizes that a 200% increase may seem somewhat unlikely today given the current supply outlook and price forecasts, the Commission finds it is essential to "stress test" the models through this planning process. Conditions and prices could change dramatically given demand domestically and internationally and the long-term viability of hydraulic fracturing. The purpose of the modeling is not to predict the future but to consider options under a broad range of scenarios.

Additionally, the previous sensitivity to reduce natural gas fuel price projections to half of the BAU projections has been removed based on several comments that natural gas fuel prices are currently at or near historic lows. The Commission expects there to be few insights gained from additional reductions in natural gas fuel prices.

For the high load sensitivity, Consumers suggests an assumed 1% increase in the annual growth rate in the event that doubling the energy and demand growth rate results in a less than 1% spread between the BAU load projection and the high load sensitivity projection. The Commission agrees with this concept but has recommended a 1.5% increase in both the spread between the projections and the annual growth rate. Again, it is important to consider "book ends" of potential outcomes, and the Commission believes 1.5% is a reasonable sensitivity given potential for new electric uses such as plug-in EVs. Also, based upon recent flat or very low load growth projections, the Commission has removed the requirement for a low load growth sensitivity. The Commission does expect to gain insights into a potential negative load-growth future from the retained high EWR sensitivity.

Consumers recommends adding a sensitivity that would model increased capacity obligations representative of 50% of the utility's retail choice load, if it has retail choice loads located in its service territory, similar to a sensitivity DTE Electric included in Case No. U-18419. ABATE suggested modeling all choice load existing in the utility's queue. The Commission adopts the proposed sensitivity of 50% of the utility's retail choice load given the uncertainty of the effects of the SRM being implemented pursuant to Section 6w of Act 341.

The EWR sensitivity has been updated for clarity and the Commission notes that the specified sensitivity represents the aggressive EWR scenario from the EWR potential study. Other edits were made to the BAU sensitivities based on multiple comments to the docket and a few of the sensitivities were removed for streamlining purposes. The sensitivity increasing the combined use of renewable energy and EWR to 50% by 2030 has been modified and moved to the Emerging Technologies Scenario.

The Commission has removed the "Disinterest in Demand Response" sensitivity, agreeing that existing utility DR programs are not likely to disappear.

3. Scenario 2 - Emerging Technologies

A clarifying sentence regarding DR has been added to the Emerging Technologies Scenario description based on feedback received. Other clarifying and prescriptive changes were made, including MEC's suggestion that a meaningful analysis of whether coal units should retire ahead of the BAU dates should be performed.

Comments were also received relative to the application of the 35% cost reduction specified for emerging technologies and revisions have been made to clarify how the 35% cost reductions should be modeled.

The Commission further notes that a revision was made to carry over a change made to the BAU scenario to include that existing PURPA contracts be assumed to be renewed.

4. Emerging Technologies Sensitivities

The Emerging Technologies Scenario has several sensitivities that are similar to the BAU sensitivities, and have been updated to be consistent with changes made to the BAU sensitivities. In addition to those changes, Consumers recommended moving the sensitivity of a 50% combined EWR and RE goal from the BAU Scenario to the Emerging Technologies Scenario, thereby removing it from the BAU Scenario. MEC requests that the Commission analyze EWR and RE in separate sensitivities and apply a 100% increase to the level of RE between 2021 and 2030. The Commission has removed the sensitivity specifying a 50% combined EWR and RE goal from the BAU Scenario and has added a sensitivity to the Emerging Technologies Scenario specifying 25% RE by 2030. The Commission acknowledges that 25% RE by 2030 is slightly less aggressive than MEC's recommendation, however, the Commission finds it a reasonable compromise between all of the comments received on the topic.

The Commission removed the previous sensitivities specifying increases and decreases in RE costs and has instead included large-scale and small-scale solar in the definition of emerging technologies. Since a 35% reduction in costs for emerging technologies is included in the description of the scenario, the Commission does not find this particular sensitivity necessary.

The Commission also removed the transportation energy sensitivity and the large electric users sensitivity. The Commission finds those sensitivity descriptions to be somewhat subjective, and without specific guidance on the projected impact to demand and load shapes to be modeled in those sensitivities. Thus, the results may or may not be useful and the Commission has removed them.

5. Scenario 3 - Environmental Policy

Several commenters request clarification regarding whether a carbon price or a hard cap on carbon emissions would be required for this scenario. Based upon the comments received, the Commission revised the IRP parameters to specify that a hard cap should be placed on carbon emissions in the model.

Consumers suggests in its comments that the Environmental Policy Scenario should use a lower load forecast than BAU due to higher prices resulting from carbon regulation. They also suggest that natural gas prices should be higher in this scenario. The Commission disagrees and offers that reductions in load forecasts and increases in natural gas prices could be subjective and that analysis of a range of potential values might be more appropriate. Thus, the Commission finds that changes in expected load and natural gas prices due to potential carbon regulations would be better achieved through sensitivity analysis as opposed to any specific singular assumption in the description of the scenario. Therefore, the Commission retains the BAU load forecast in order to minimize the differences between the scenarios and allow for a comparison of results across scenarios. Thus, the hard cap on emissions remains and the Commission will not introduce changes to the load forecast or natural gas price forecast at the same time. Changes in load and changes in natural gas price forecast would still be captured in the sensitivities required, and the Commission notes that the high EWR sensitivity would likely provide similar results to a low load sensitivity with baseline EWR assumptions.

The Commission also reviewed comments opposing the assumption that nuclear units have license renewals granted and remain online. The Commission disagrees, given nuclear units remaining online is more likely to happen in a carbon-constrained world. Therefore, the Commission maintains this parameter specifically for the Environmental Policy Scenario.

The Commission has carried over the language specifying that existing PURPA contracts should be assumed to be renewed in the Environmental Policy Scenario, similar to the other scenarios.

Finally, the Commission has clarified that not less than 35% of the state's electric needs should be met through a combination of EWR and RE by 2025 based upon provisions in Act 342.

6. Environmental Policy Sensitivities

Many of the changes made to the Environmental Policy sensitivities have been previously discussed and have been revised to be consistent with changes made to the sensitivities in the BAU and Emerging Technologies Scenarios. Additionally, the assumption that all coal-fired generation is retired by 2035 has been removed to allow the specified carbon reductions and economics to determine when coal units will retire.

7. Scenario 4 - High Market Price Variant

Although no specific comments were received on the MISO Zone 2 UP scenario or sensitivities, the Commission updated the UP sensitivities in a similar manner to what has been proposed in the other three scenarios. The Commission did, however, receive several comments recommending an inclusive IRP for the entire UP. Given the number of non-Commission jurisdictional utilities in the UP, the Commission cannot mandate a single IRP for the region or order electric cooperatives or municipal utilities to participate in such planning. Nonetheless, the Commission encourages collaboration and coordination on the development of individual IRPs for UMERC and UPPCO and notes that MAE is exploring planning issues for the UP.

IX. Michigan Integrated Resource Planning Modeling Input Assumptions and Sources

The table shown in the Michigan IRP Modeling Input Assumptions and Sources section has also been updated to reflect comments received. The Commission reviewed several comments from different entities who suggested that a longer study period would be beneficial to the IRP process because long-term decisions should be based upon the net present value of revenue requirements over a longer term. The Commission agrees and has increased the study period to 20 years while retaining the requirement to provide a projection of the utility's load and reliability obligations, as well as a plan to meet those obligations at 5, 10, and 15-year intervals.

Several commenters submitted opinions or suggestions regarding the model region and areas adjacent to the utility service area. The Commission updated the model region based on a combination of those comments.

Comments submitted by the EG[1] suggest that the Commission clarify item 10, EWR Costs, to ensure that EWR costs reflect program administrator costs only, and do not include participant costs. The Commission agrees with this suggestion. Therefore, table item 10 has been updated.

X. Additional Integrated Resource Planning Requirements and Assumptions

DTE Electric suggests that forecasted EWR savings should be aggregated into hourly units, coincident with hourly load forecasts, with indicative estimates of efficiency cost and savings on

[1] Comments received from the EG included a report from Synapse Energy Economics that outlined this suggestion.

an hourly basis. The Commission agrees and adopted this suggestion as bullet number nine of this section.

Multiple comments were submitted regarding the retirement of existing resources. The Commission clarified the retirement assumptions in each of the required scenarios as well as in section X. As previously discussed, the Commission clarifies that it not necessary to allow the model to retire units economically that it does not own, however the Commission finds value in letting the model retire company-owned units based upon economics. The Commission is sympathetic to concerns related to modeling time and has specified specific situations in the Emerging Technologies Scenario and the Environmental Policy Scenario where only the utility's remaining coal units, as opposed to all of the utility's units, be available for the model to retire based upon economics. In the BAU Scenario and the High Market Price Variant Scenario, the utilities are allowed more flexibility in the methodology used to determine the retirement of utility-owned units, but are also not precluded from allowing the model to retire them based upon economics. The Commission also clarifies in Section X that the utility shall clearly identify in each scenario and sensitivity, all unit retirement assumptions, and unless otherwise specified in the description of the *required* scenarios and sensitivities, the utility has flexibility to allow the model to select retirement of the utility's existing generation resources, rather than limiting retirements to input assumptions. The Commission reiterates, that any additional scenario and sensitivity analyses presented in an IRP that are over and above the required scenarios and sensitivities, may include differing assumptions and sources, including retirement assumptions, as deemed appropriate by the utility. The UPACC recommendsthat the IRPs include an analysis regarding how incremental investments would compare to large investments in specific technologies that might be obsolete in a few years. The Commission finds this suggested analysis to be reasonable and has included it.

Finally, addressing MEGA's request for waivers, the Commission is sympathetic to the needs of smaller utilities and intends to address those concerns, along with requests for waivers, in the IRP filing requirements docket. The Commission also expects that the more streamlined set of scenarios and sensitivities adopted in the final planning parameters may be more accommodating for small utilities without compromising analyses that are essential to making informed decisions that benefit customers regardless of the utility's size.

Conclusion

Establishing the new IRP process pursuant to the requirements of MCL 460.6t(1) was a major undertaking. The Commission especially appreciates the significant efforts by the Staff, the thoughtful and constructive input from stakeholders, and the coordination with and contributions from MAE and the MDEQ. This collaborative effort has resulted the final MIRPP, attached as Exhibit A. The Commission is confident that the MIRPP and resulting individual utility IRP filings will greatly enhance its efforts to understand Michigan's future electricity needs and its ability to explore different solutions to meet those needs in an affordable, reliable manner that is protective of the environment. The IRP parameters set forth in this order and Exhibit A will also help ensure that decisions we make about the state's energy supplies can adapt to changing conditions. This is essential given the stakes involved and the dynamic nature of the energy industry, customer behavior, and technology trends. The Commission expects a planning process that is transparent, thorough, and open to considering evolving technologies, ownership structures, and innovative solutions to meet customer needs. In applying the "most reasonable and prudent" standard, it is essential to fully evaluate alternatives ranging from conventional or distributed generation, transmission or distribution, energy storage, and EWR or DR programs. Over time, the Commission expects the IRP process and modeling approaches to evolve, and will need to be more integrated with other planning efforts at the transmission and distribution levels. While not explicitly required by this order, the Commission also encourages utilities to develop meaningful opportunities for stakeholders to engage early in the planning process, including opportunities before formal filings are made at the Commission. Such engagement should ultimately lead to more informed decisions by the Commission on important energy choices that will affect utility customers for decades.

THEREFORE, IT IS ORDERED that:

A. The Michigan Integrated Resource Planning Parameters, attached as Exhibit A, complies with the mandates set forth in MCL 460.6t(1) and (2) and is approved by the Commission.

B. Each electric utility whose rates are regulated by the Commission shall demonstrate compliance with the Michigan Integrated Resource Planning Parameters as a condition of Commission approval of its respective integrated resource plan pursuant to MCL 460.6t(3).

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

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Sally A. Talberg, Chairman

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Norman J. Saari, Commissioner

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Rachael A. Eubanks, Commissioner

By its action of November 21, 2017.

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Kavita Kale, Executive Secretary

EXHIBIT A

MICHIGAN INTEGRATED RESOURCE PLANNING PARAMETERS

Pursuant to Public Act 341 of 2016, Section 6t

November 21, 2017

I. Table of Contents

II. Executive Summary

This Michigan Integrated Resource Planning Parameters document was developed as a part of the implementation of the provisions of Public Act 341 of 2016 (PA 341), Section 6t. This document includes three integrated resource plan (IRP) modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Upper Peninsula, and three IRP modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Lower Peninsula. None of the scenarios, sensitivities or other modeling parameters included within this document should be construed as policy goals or even as likely predictions of the future. Instead, the scenarios, sensitivities and modeling parameters are more aptly characterized as stressors utilized to test how different future resource plans perform relative to each other with respect to affordability, reliability, adaptability, and environmental stewardship. In some instances, scenarios and sensitivities intentionally push the boundaries on what may be viewed as probable and could be considered as bookends on the range of possible future outcomes. Utilities may also include separate additional scenarios and sensitivities in their IRPs, and may use different assumptions or forecasts for the additional scenarios and sensitivities. However, the assumptions and parameters outlined in this document should be used for the required scenarios and sensitivities. Including the scenarios will ensure that Michigan's electric utilities will consider a wide variety of resources such as renewable energy, demand response, energy waste reduction, storage, distributed generation technologies, voltage support solutions, and transmission and non-transmission alternatives, in addition to traditional fossil-fueled generation alternatives for the future. This IRP parameters document also contains numerous modeling assumptions and requirements, requires sensitivities for each scenario, identifies significant environmental regulations and laws that effect electric utilities in the state, and identifies required planning reserve margins and local clearing requirements in areas of the state.

The Demand Response Potential Study was completed in September 2017 and the assessment of Energy Waste Reduction Potential was completed in August 2017. Both studies have influence on integrated resource planning and are incorporated into the Commission's Docket (Case No. U-18418[1]) for the implementation of the provisions of PA 341 Section 6t.

Section 6t (1) requires that the IRP parameters, required modeling scenarios and sensitivities, applicable reliability requirements, applicable environmental rules and regulations, and the demand response and energy waste reduction potential studies be re-examined every five years. The next 120-day proceeding to conduct these assessments and gather input should commence in July 2022.

III. Background

On December 21, 2016, Governor Rick Snyder signed PA 341 into law, which amended Public Act 3 of 1939 and became effective on April 20, 2017. The law requires the Michigan Public Service Commission (MPSC or Commission), with input from the Michigan Agency for

[1] http://efile.mpsc.state.mi.us/efile/viewcase.php?casenum=18418&submit.x=0&submit.y=0

Energy (MAE), Michigan Department of Environmental Quality (MDEQ), and other interested parties to set modeling parameters and assumptions for utilities to use in filing integrated resource plans. PA 341 then requires rate-regulated electric utilities to submit IRPs to the MPSC for review and approval.

The MPSC, MAE, and MDEQ Staff (Staff) began the collaborative process on March 10, 2017 with state-wide participation from a wide-range of stakeholders (listed in Appendix A). To address the requirements of PA 341 Section 6t (1), subsections (a) through (e), and to develop the modeling assumptions, scenarios, and sensitivities pursuant to Section 6t (1), subsection (f), eight workgroups were formed:

1. Energy Waste Reduction, to address MCL 460.6t (1) subsections (a) and (f) (iii)
2. Demand Response, to address MCL 460.6t (1) subsections (b) and (f) (iii)
3. Environmental Policy, to address MCL 460.6t (1) subsections (c), (d), and (f) (ii)
4. Renewables and PURPA, to address MCL 460.6t (1) subsection (f) (iii)
5. Forecasting, Fuel Prices and Reliability, to address MCL 460.6t (1) subsections (e) and (f) (i), (iii), (iv) and (v)
6. Transmission, to address MCL 460.6t (1) subsection (f) (iii)
7. Other Market Options and Advanced Technologies, to address MCL 460.6t (1) subsection (f) (iii)
8. Upper Peninsula (Zone 2), to address MCL 460.6t (1) subsections (f) (i) and (iv)

Stakeholders were invited to participate in and assist with leading the various workgroups. The workgroups met regularly from late March to mid-June to discuss how to address various subsections of PA 341 Section 6t. On June 19, each workgroup submitted recommendations to the Staff for potential inclusion into this IRP parameter document. Further details on the events that have taken place with stakeholder involvement in the development of the concepts included in this document are included on the energy legislation implementation website.[2]

The Commission released an earlier draft of this document with a Commission Order initiating Case No. U-18418 on July 31, 2017. Interested parties were provided an opportunity to file comments and reply comments in Case No. U-18418. The Commission has considered the comments and reply comments and has incorporated several changes herein.

IV. Energy Waste Reduction Potential Study

To comply with PA 341 Section 6t (1) (a) and (f) (iii)

The statewide assessment of energy waste reduction (EWR) potential was built upon existing studies provided by two, utility-specific 20-year potential studies conducted in 2016, by GDS Associates, Inc. (GDS). These utility-specific EWR potential studies are considered by MPSC

[2] http://www.michigan.gov/mpsc/0,4639,7-159-80741_80743-406248--,00.html

Staff to represent potential values which reflect a 'business as usual' assessment of achievable, technical and economic potential consistent with requirements of the prior energy law, Public Act 295 of 2008 (PA 295).[3] In determining a statewide assessment, MPSC Staff was cognizant of stakeholder feedback and therefore attempted to consider the Lower Peninsula separately from the Upper Peninsula assessment as discussed below.

Lower Peninsula. In order to develop additional data points which reflect the incremental EWR potential possible under more aggressive program goals consistent with Public Acts 341 and 342 of 2016, stakeholders first combined the separate utility-specific potential studies into a Lower Peninsula study, resulting in an assessment of EWR potential under PA 295 era, business as usual assumptions. From there, stakeholders developed additional modeling scenarios and sensitivities designed to assess additional cost effective EWR savings available with more aggressive programs.

The business as usual assessment and supplemental study results[4] were combined into one report and can be found on the energy legislation implementation webpage for the EWR Potential Study. This study includes the combined business as usual potential results on pages 1 through 85, with the additional potential identified under more aggressive EWR programs, summarized starting on page 87. The EWR supply curves for the business as usual assumptions and more aggressive scenarios are found in Appendix G, starting on page 277 of the report. The modeling scenarios, assumptions, and sensitivities for the supplemental study are briefly summarized below with details provided on the webpage.[5]

Scenario #1: Sensitivity on Incentive Levels – GDS revised the basic analysis of Achievable Potential for the Consumers Energy Company and the DTE Electric Company service areas using the assumption that the programs would pay 100% of incremental costs[6] for all measures/bundles of measures that would still pass the Utility Cost Test at the higher incentive level (i.e., if the program's paid incentives equal to 100% of incremental cost of the measure, as opposed to using the 50% of incremental cost assumption.)

Scenario #2: Aggressive Investment/Emerging Technologies – assumes higher avoided cost for energy and capacity (such as due to higher gas prices), incentives at 100% of the measure's incremental cost, optimistic market penetration, and inclusion of some emerging technologies that are presumed to be cost-effective.

Scenario #3: Environmental Regulation – assumes environmental regulations have increased electric avoided costs reflecting a monetary value for decreasing carbon emissions.

Upper Peninsula. The Upper Peninsula potential study assessment also built upon the foundation of existing utility-specific potential studies. Efforts were made to incorporate

[3] Public Act 295 Energy Optimization programs contained caps on program spending which were removed in the Public Act 342 Energy Waste Reduction programs.
[4] See supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf
[5] For more details on the assumptions for the supplemental EWR study for the Lower Peninsula, see http://www.michigan.gov/documents/mpsc/Scenario_assumptions-_07.09.17_599440_7.docx.
[6] For Low-Income measures, the utilities are assumed to pay 100% of the measure cost.

assumptions which reflected the additional opportunities for EWR potential of the Upper Peninsula due to the generally higher cost of electricity in that region.

The analysis utilized historic and forecast data compiled for the load serving entities in that region for the 20-year period starting in 2016, with estimates for the number of Upper Peninsula region electric customers, sales by sector (i.e., residential, commercial, industrial), and Upper Peninsula region peak load data. The analysis also included background data from existing potential studies from service territories which most closely resembled the rural nature and dispersed populations found in the service territories in the Upper Peninsula.

The final result of this modest analysis provides a business as usual estimate of EWR potential under base case assumptions. Additional work would be required to further assess the potential for EWR under the more aggressive modeling scenario/sensitivities.

Statewide Assessment of EWR Potential. The additional assessments for EWR potential for the Lower and Upper Peninsulas for the 2017 through 2036 timeframe were completed in mid-August and together form the basis for the MPSC Staff's statewide assessment of EWR potential. These assessments include supply curves for the Lower Peninsula. As previously mentioned, these studies are available on the MPSC Energy Legislation webpage.[7]

V. Demand Response Potential Study

To comply with PA 341 Section 6t (1) (b)

To comply with Section 6t, Staff determined that the assessment for use of demand response programs would best be comprised of two parts: a technical study[8] and a market assessment.[9]

Technical Study. The technical potential study estimates the technical and achievable potential for reducing on-peak electricity usage through demand response programs for all customer classes. The study determines demand response potential for the 20-year period beginning in 2018.

In the technical study, demand response potential is calculated using data and assumptions for inputs such as customer eligibility, likely participation rates, per customer demand reduction, program costs, avoided costs, etc. This quantitative measure of demand response potential and the costs and savings associated with potential resources have been used as an input for the IRP modeling scenarios.

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[7] See supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf; See also assumptions for supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

[8] Demand Response Potential Study, http://www.michigan.gov/documents/mpsc/State_of_Michigan_-_Demand_Response_Potential_Report_-_Final_29sep2017__602435_7.pdf.

[9] Demand Response Market Assessment, http://www.michigan.gov/documents/mpsc/MI_Demand_Response_Market_Assessment_20170929_602432_7.pdf.

Demand response programs considered by the study include behavioral programs, time-of-use pricing, direct load control, interruptible and curtailment, ancillary service, and more. Programs are modeled by customer class. Pre-existing demand response programs were not favored over not-yet-existing programs in the calculation of statewide potential.

The study results in two levels of realistically achievable amounts of demand response potential, called the integrated low case and integrated high case. The low case is the product of more conservative assumptions for program participation and enabling technology penetration, while the high case assumes higher participation. For example, the low case assumes residential time-of-use rates are opt-in for customers, resulting in lower participation than the high case, where time-of-use rates are opt-out. Full details on all of the assumptions relied upon are described in the study.

Market Assessment. The market assessment examines the potential for demand response for large commercial and industrial (LCI) customers through surveys, interviews, and analysis of the customer class. This approach evaluates the LCI customer's capability, desire, and motivation to participate in demand response programs by gathering that information directly from those customers to determine interest and capability for participating in demand response programs, identifying any barriers to participation, and evaluating a reasonable and achievable potential for peak load management in Michigan.

LCI customers are defined as non-residential, non-lighting customers that have a maximum annual demand of greater than or equal to 1 MW. Given the wide diversity of load profiles in the LCI class and the constrained timeline for the market assessment, it was best to focus on the largest (by demand) customers first. Also, LCI customers represent a large portion of statewide load and have shown to be highly receptive to demand response programs.

By surveying LCI customers to determine the parameters of a demand response program that would maximize their participation, the market assessment provides better insight on customers' energy needs to inform effective program design and better inform the statewide assessment.

When combined into a comprehensive statewide assessment of demand response potential, the results of the two studies provide demand response resources, with cost and megawatt load reduction per program that can compete directly with supply-side options in the IRP modeling process. The IRP model will choose the most economical way to meet load, whether the resource increases supply or decreases demand. The potential study provides the data necessary, including the limits of the demand side resources, to allow all methods to meet load to compete equally.

Study and Stakeholder Process. MPSC Staff met with the demand response workgroup in March and April to develop scopes for the two-part study. After combining the ideas and comments of stakeholders in the workgroup, MPSC Staff issued requests for proposals in May. Bids were received and evaluated in June, and contracts for the two studies were awarded. The contractors delivered the final statewide potential study on September 29, 2017. The final study integrates results of the market assessment.

VI. State and Federal Environmental Regulations, Laws and Rules

Appendix E contains a regulatory timeline of the environmental regulations, laws and rules discussed in this section.

To comply with PA 341 Section 6t (1) (c)

Federal rules and laws:

Clean Air Act – The Clean Air Act is a United States federal law designed to control air pollution on a national level. The Clean Air Act is a comprehensive law that established the National Ambient Air Quality Standards (NAAQS), Maximum Achievable Control Technology Standards (MACT), Hazardous Air Pollutant Standards, and numerous other regulations to address pollution from stationary and mobile sources.

National Ambient Air Quality Standards – Title 1 of the Clean Air Act requires the United States Environmental Protection Agency (EPA) to set NAAQS for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standards are set at a level that is protective of health with an adequate margin of safety. Secondary standards are protective of public welfare, including protection from damage to crops, forests, buildings, or the impairment of visibility. The adequacy of each standard is to be reviewed every five years. The six pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.[10]

Nonattainment areas are regions that fail to meet the NAAQS. Locations where air pollution levels are found to contribute significantly to violations or maintenance impairment in another area may also be designated nonattainment. These target areas are expected to make continuous, forward progress in controlling emissions within their boundaries. Those that do not abide by the Clean Air Act requirements to reign in the emissions of the pollutants are subject to EPA sanctions, either through the loss of federal subsidies or by the imposition of controls through preemption of local or state law. States are tasked with developing strategic plans to achieve attainment, adopting legal authority to accomplish the reductions, submitting the plans to the EPA for approval into the State Implementation Plan, and ensuring attainment occurs by the statutory deadline. States may also submit a plan to maintain the NAAQS into the future along with contingency measures that will be implemented to promptly correct any future violation of the NAAQS.

Sulfur Dioxide Nonattainment Areas – In 2010, the EPA strengthened the primary NAAQS for SO_2, establishing a new 1-hour standard of 75 parts per billion (ppb).

A federal consent order set deadlines for the EPA to designate nonattainment areas in several rounds. Round one designations were made in October 2013, based on violations of the NAAQS at ambient monitors. A portion of Wayne County was designated nonattainment.

[10] The most recent NAAQS can be accessed here: https://www.epa.gov/criteria-air-pollutants/naaqs-table.

The area must attain the NAAQS by October 2018. The state's attainment plan was due to the EPA by April 2015.

Round two designations were based on modeling of emissions from sources emitting over 2000 tons of SO_2 per year. A portion of St. Clair County was designated nonattainment in September 2016. Attainment must be achieved by September 2021, and the state's attainment plan is due to the EPA by March 2018.

Round three designations will address all remaining undesignated areas by December 31, 2017. The EPA sent a letter to Governor Snyder on August 22, 2017, 120 days prior to the intended designation date, indicating that Alpena County and Delta County are to be designated as unclassifiable/attainment areas. Remaining areas of Michigan that were not required to be characterized and for which the EPA does not have information suggesting that the area may not be meeting the NAAQS, or contributing to air quality violations in a nearby area that does not meet the NAAQS, are intended to also be designated as unclassifiable/attainment.

Cross-State Air Pollution Rule – The Cross-State Air Pollution Rule (CSAPR) was promulgated to address air pollution from upwind states that is transported across state lines and impacts the ability of downwind states to attain air quality standards. The rule was developed in response to the Good Neighbor obligations under the Clean Air Act for the ozone standards and fine particulate matter standards. CSAPR is a cap and trade rule which governs the emission of SO_2 and NO_x from fossil-fueled electric generating units through an allowance-based program. Under this program, NO_x is regulated on both an annual basis and during the ozone season (May through September). Each allowance (annual or ozone) permits the emission of one ton of NO_x, with the emissions cap and number of allocated allowances decreasing over time. Recently, the EPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May 2017. In the future, the state will have Good Neighbor obligations for the 2015 ozone standard.

Mercury and Air Toxics Standards – Section 302 of the Clean Air Act requires the EPA to adopt maximum available control technology standards for hazardous air pollutants. The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires new and existing oil and coal-fueled facilities to achieve emission standards for mercury, acid gases, certain metals, and organic constituents. Existing sources were required to comply with these standards by April 16, 2015. Some individual sources were granted an additional year, at the discretion of the Air Quality Division of the MDEQ. In June 2015, the United States Supreme Court found that the EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the DC Circuit Court of Appeals ruled that MATS may be enforced as the EPA modifies the rule to comply with the United States Supreme Court decision. The deadline for MATS compliance for all electric generating units was April 16, 2016.

Clean Air Act Section 111(b), Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units – New Source Performance Standards (NSPS) are established under Section 111(b) of the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the EPA finalized a NSPS that established standards for emissions of carbon dioxide for newly constructed, modified, and reconstructed fossil-fuel fired electric generating units. There are different standards of performance for fossil fuel-fired steam generating units and fossil fuel-fired combustion turbines.[11]

Clean Air Act Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the Clean Air Act requires the EPA to establish standards for certain existing industrial sources. The final Clean Power Plan, promulgated on October 23, 2015, addressed carbon emissions from electric generating units. The Clean Power Plan established interim and final statewide goals and tasked states with developing and implementing plans for meeting the goals. Michigan's final goal was to reduce carbon dioxide emissions by 31 percent from a 2005 baseline by 2030.[12]

On February 9, 2016, the United States Supreme Court issued five orders granting a stay of the Clean Power Plan pending judicial review. On March 28, 2017, President Trump signed an Executive Order directing the EPA to review the Clean Power Plan and the standards of performance for new, modified, and reconstructed electric generating units (section 111(b) rule). As a result, the Department of Justice filed motions to hold those cases in abeyance pending the EPA's review of both rules, including through the conclusion of any rulemaking process that results from that review. The Clean Power Plan does not currently affect Michigan utilities, however due to the EPA's 2009 endangerment finding on greenhouse gases, utilities should address their future anticipated greenhouse gas emissions.

Greenhouse Gas Reporting Program – The Greenhouse Gas Reporting Program (codified at 40 CFR Part 98) tracks facility-level emissions of greenhouse gas from large emitting facilities, suppliers of fossil fuels, suppliers of industrial gases that result in greenhouse gas emissions when used, and facilities that inject carbon dioxide underground. Facilities calculate their emissions using approved methodologies and report the data to the EPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year. The EPA conducts a multi-step verification process to ensure reported data is accurate, complete and consistent. This data is made available to the public in October of each year through several data portals.

Boiler Maximum Achievable Control Technology – The Boiler MACT establishes national emission standards for hazardous air pollutants from three major source categories: industrial boilers, commercial and institutional boilers, and process heaters. The final emission standards for control of mercury, hydrogen chloride, particulate matter (as a surrogate for non-mercury metals), and carbon monoxide (as a surrogate for organic hazardous emissions) from coal-fired, biomass-fired, and liquid-fired major source boilers are based on the MACT. In addition, all

[11] The 111(b) standards can be found in Table 1 here: https://www.federalregister.gov/documents/2015/10/23/2015-22837/standards-of-performance-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed-stationary.

[12] The 111(d) rule can be viewed in full here: https://www.federalregister.gov/documents/2015/10/23/2015-22842/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

major source boilers and process heaters are subject to a work practice standard to periodically conduct tune-ups of the boiler or process heater.

Regional Haze – Section 169 of the federal Clean Air Act sets forth the provisions to improve visibility, or visual air quality, in 156 national parks and wilderness areas across the country by establishing a national goal to remedy impairment of visibility in Class 1 federal areas from manmade air pollution. States must ensure that emission reductions occur over a period of time to achieve natural conditions by 2064. Air pollutants that have the potential to affect visibility include fine particulates, nitrogen oxides, sulfur dioxide, certain volatile organic compounds and ammonia. The 1999 Regional Haze rule required states to evaluate the best available retrofit technology (BART) to address visibility impairment from certain categories of major stationary sources built between 1962 and 1977. A BART analysis considered five factors as part of each source-specific analysis: 1) the costs of compliance, 2) the energy and non-air quality environmental impacts of compliance, 3) any existing pollution control technology in use at the source, 4) the remaining useful life of the source, and 5) the degree of visibility improvement that may reasonably be anticipated to result from use of such technology. For fossil-fueled electric generating plants with a total generating capacity in excess of 750 MW, states must use guidelines promulgated by the EPA. In 2005, the EPA published the guidelines for BART determinations. Michigan has met the initial BART determination requirements. In December 2016, the EPA issued a final rule setting revised and clarifying requirements for periodic updates in state plans. The next periodic update is due July 31, 2021. There are two Class 1 areas in Michigan: Seney National Wildlife Refuge and Isle Royal National Park. Michigan also has an obligation to eliminate the state's contribution to impairment in Class 1 areas in other states.

Resource Conservation and Recovery Act – The Resource Conservation and Recovery Act (RCRA) gives the EPA the authority to control hazardous waste from the "cradle-to-grave", which includes the generation, transportation, treatment, storage, and disposal of hazardous waste. RCRA also set forth a framework for the management of non-hazardous solid wastes.

In April 2015, the EPA established requirements for the safe disposal of coal combustion residuals produced at electric utilities and independent power producers. These requirements were established under Subtitle D of RCRA and apply to coal combustion residual landfills and surface impoundments. Michigan electric utilities must comply with these regulations.

Clean Water Act – The Clean Water Act is a United States federal law designed to control water pollution on a national level.

Clean Water Act Section 316(b) – The EPA promulgated rules under Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures at new and existing facilities in order to minimize the impingement and entrainment of fish and other aquatic organisms at these structures. Section 316(b) applies to existing electric generation facilities with a design intake flow greater than two million gallons per day that use at least twenty-five percent of the water withdrawn from the surface waters of the United States for cooling purposes.

In 2001, the EPA promulgated rules specific to cooling water intake structures at new facilities. Generally, new Greenfield, stand-alone facilities are required to construct the facility to limit the intake capacity and velocity requirements commensurate with that achievable with a closed-cycle, recirculating cooling system.

Following a previously promulgated version of the rules and judicial remand, the regulations for existing facilities were promulgated in August 2014. These rules were also challenged and undergoing judicial review. According to the published rules, any facility subject to the existing facilities rule must identify which one of the seven alternatives identified in the best technology available (BTA) standard will be met for compliance with minimizing impingement mortality. The rules do not specify national BTA standards for minimizing entrainment mortality, but instead require that the MDEQ establish the BTA entrainment requirements for a facility on a site-specific basis. These BTA requirements are established after consideration of the specific factors spelled out in the rule. Facilities with actual flows in excess of 125 million gallons per day must provide an entrainment study with its National Pollutant Discharge Elimination System (NPDES) permit application. While the rules do not specify a deadline for compliance of the rules, facilities will need to achieve the impingement and entrainment mortality standards as soon as practicable according to the schedule of requirements set by the MDEQ following NPDES permit reissuance.

Steam Electric Effluent Guidelines – The Steam Electric Effluent Guidelines (SEEG), promulgated under the Clean Water Act, strengthens the technology-based effluent limitations guidelines and standards for the steam electric power generating industry. The 2015 amendment to the rule established national limits on the amount of toxic metals and other pollutants that steam electric power plants are allowed to discharge. Multiple petitions for review challenging the regulations were consolidated in the United States Court of Appeals for the Fifth Circuit on December 8, 2015. On April 25, 2017 the EPA issued an administrative stay of the compliance dates in the effluent limitations guidelines and standards rule that have not yet passed pending judicial review. In addition, the EPA requested, and was granted, a 120-day stay of the litigation (until September 12, 2017) to allow the EPA to consider the merits of the petitions for reconsideration of the Rule. On August 11, 2017, the EPA provided notice that it will conduct a rulemaking to potentially revise the new, more stringent BTA effluent limitations and Pretreatment Standards for Existing Sources in the 2015 rule that apply to bottom ash transport water and flue gas desulfurization wastewater. The EPA will provide notice and an opportunity for comment on any proposed revisions to the rule and will notify the United States Court of Appeals that it seeks to have challenges to those portions of the rule severed and held in abeyance pending completion of the rulemaking. On September 18, 2017 the 120-day administrative stay was lifted postponing certain compliance deadlines. The earliest date for compliance with SEEG is November 1, 2020, while the latest compliance date of December 31, 2023 remains unchanged.

State Rules and Laws:

Michigan Mercury Rule – The purpose of the Michigan Mercury Rule (MMR) is to regulate the emissions of mercury in the State of Michigan. Existing coal-fired electric generating units must choose one of three methods to comply with the emission limits and any new electric generating unit will be required to utilize Best Available Control Technology. The MMR is identical to the MATS in its limitations and all compliance dates for this rule have since past.

Michigan Environmental Protection Act (MEPA) – Part 17 of Michigan's Natural Resources and Environmental Protection Act (NREPA), 1994 PA 451. Under MEPA, the attorney general or any person may maintain an action for an alleged violation or when one is likely to occur for declaratory and equitable relief against any person for the protection of the air, water, and other natural resources and the public trust in these resources from pollution, impairment, or destruction. MEPA also provides for consideration of environmental impairment and whether a feasible and prudent alternative exists to any impairment consistent with the promotion of the public health, safety, and welfare in light of the state's paramount concern for the protection of its natural resources from pollution, impairment, or destruction.

Solid Waste Management (Part 115) – Part 115 of the Michigan NREPA regulates coal combustion residuals (CCR) as a solid waste. It requires any CCR that will remain in place in a surface impoundment or landfill be subject to siting criteria, permitting and licensing of the disposal area, construction standards for the disposal area, groundwater monitoring, corrective action, and financial assurance and post-closure care for a 30-year period. The disposal facility is required to maintain the financial assurance to conduct groundwater monitoring throughout the post-closure care period.

The disposal of CCR is currently dually regulated under the RCRA rule published in April 2015, and under Part 115 of the NREPA. However, in December 2016, the Water Infrastructure Improvements for the Nation Act was passed, which included an amendment to Section 4005 of RCRA providing a mechanism to allow states to develop a state permitting program for regulation of CCR units. Upon approval of a state program, the RCRA regulations would be enforced by states and the CCR units would not be subject to the dual regulatory structure. Michigan is in the process of developing a permit program for submittal to the EPA.

To comply with PA 341 Section 6t (1) (d)

A list of federal and state environmental regulations, laws and rules formally proposed have been identified as required by Section 6t (1) (d):

Ozone Nonattainment Areas – The ozone NAAQS was revised by the EPA in 2015 from 75 ppb to 70 ppb. Nonattainment designations were to be made by October 2017. In June 2017, the EPA announced a decision to delay making designations by one year. More recently on August 2, 2017, the EPA withdrew its plan to delay designations. Michigan is expecting ten counties, or portions of counties, to be designated nonattainment, including Wayne, Oakland, Macomb, St. Clair, Livingston, Washtenaw, and Monroe in Southeast Michigan and Muskegon, Allegan, and Berrien in West Michigan. Deadlines and requirements for ozone nonattainment areas are dependent on the classification assigned to the nonattainment area. All ozone nonattainment areas in Michigan are expected to be classified "Marginal". This classification would establish an attainment deadline of 2020 or 2021 depending on the date of designation, and an attainment plan submittal deadline of 2020 or 2021. In addition to the requirement to attain by the deadline, there will also be more stringent requirements for major source air permits, including lowest achievable emission rate conditions and offsets for new emissions of the ozone precursors of nitrogen oxides and volatile organic compounds.

To comply with PA 341 Section 6t (5) (m)

"How the utility will comply with all applicable state and federal environmental regulations, laws and rules, and the projected costs of complying with those regulations, laws and rules.*"*

In developing its IRP, a utility should present an environmental compliance strategy which demonstrates how the utility will comply with all applicable federal and state environmental regulations, laws and rules. Included with this information, the utility should analyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utilities generation fleet, and include the relevant future compliance costs within the IRP model. Review and approval of an electric utility's integrated resource plan by the Michigan Public Service Commission does not constitute a finding of actual compliance with applicable state and federal environmental laws. Electric utilities that construct and operate a facility included in an approved integrated resource plan remain responsible for complying with all applicable state and federal environmental laws.

VII. Planning Reserve Margins and Local Clearing Requirements

To comply with PA 341 Section 6t (1) (e)

Compliance with Section 6t (1) (e) requires the identification of any required planning reserve margins and local clearing requirements in areas of the state of Michigan. The majority of Michigan is part of the Midcontinent Independent System Operator (MISO). MISO is divided into local resource zones (Zones) with the majority of the Lower Peninsula in Zone 7 and the Upper Peninsula combined with a large portion of Wisconsin in Zone 2, as shown in Appendix B. The unshaded portion of the southwest area of the Lower Peninsula is served by the PJM regional transmission operator. While the PJM has similar reliability criteria to MISO, there are some differences in terminology and details.

MISO publishes planning reserve margins in its annual Loss of Load Expectation (LOLE) Study Report each November.[13] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins 2018 through 2027" for the entire footprint.[14] MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report.[15] The local reliability requirement is a measure of the planning resources required to be physically located inside a local resource zone without considering any imports from outside of the zone in order to meet the reliability criterion of one day in ten years LOLE. The MISO Local Clearing Requirement is defined as "the minimum amount of unforced capacity that is physically located within the Zone that is required to meet

[13] MISO 2018 – 2019 Loss of Load Expectation Study Report published in October 2017, https://www.misoenergy.org/Library/Repository/Study/LOLE/2018%20LOLE%20Study%20Report.pdf

[14] Three of the next ten years planning reserve margins are modeled by MISO and the remaining of the ten years are interpolated and reported in the MISO Loss of Load Expectation Study.

[15] MISO models the local reliability requirement for the prompt year, one of the future years in between year 2 and year 5, and one future year in between year 6 and year 10.

the LOLE requirement while fully using the Capacity Import Limit for such."[16] The Local Clearing Requirement for each zone is reported annually with the MISO planning resource auction results in April.[17]

For the southwest corner of the Lower Peninsula, in PJM's territory,[18] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[19] PJM outlines requirements for an Installed Reserve Margin, similar to MISO's planning reserve margin on an installed capacity basis, and a Forecast Pool Requirement on an unforced capacity basis, similar to MISO's planning reserve margin on an unforced capacity basis. PJM also specifies 27 Local Deliverability Areas somewhat similar to MISO's local resource zones. PJM publishes a Reserve Requirement Study[20] annually in October containing the requirements for generator owners and load serving entities within its footprint for the next ten years.

Electric utilities required to file integrated resource plans under Section 6t are also required to annually make demonstrations to the MPSC that they have adequate resources to serve anticipated customer needs four years into the future, pursuant to Section 6w of PA 341. On September 15, 2017, in Case No. U-18197, the MPSC adopted an order establishing a capacity demonstration process in an effort to implement the State Reliability Mechanism (SRM) requirements of Section 6w. This order established SRM-specific planning reserve margin requirements for each electric provider in Michigan for the period of planning years 2018 through 2021. In an order issued on October 14, 2017, in Case No. U-18444, the MPSC initiated a proceeding to establish a methodology to determine a forward locational requirement, to establish a methodology to determine a forward planning reserve margin requirement, and to establish these requirements for planning year 2022. In addition to planning to meet the reliability requirements of the regional grid operator (MISO or PJM, as applicable), electric utility IRP filings should be consistent with the requirements of the State Reliability Mechanism under Section 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiated to implement these provisions.

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[16] Federal Energy Regulatory Commission Electric Tariff, Module E-1, 1.365a. 1.0.0.

[17] MISO Planning Resource Auction results, April 2017, https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/Planning%20Year%2017-18/2017-2018%20Planning%20Resource%20Adequacy%20Results.pdf.

[18] See Appendix C for a map of PJM Local Deliverability Areas.

[19] PJM Manual 18 for the PJM Capacity Market, https://www.pjm.com/~/media/documents/manuals/m18.ashx.

[20] PJM Reserve Requirement Study, October 2017, http://www.pjm.com/-/media/committees-groups/committees/mrc/20171026/20171026-item-05-2017-irm-study.ashx.

VIII. Modeling Scenarios, Sensitivities and Assumptions

To comply with PA 341 Section 6t (1) (f)

For utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, three modeling scenarios are required. There is a total of four unique scenarios included in this IRP parameters document; the applicability of each is described within the narrative of each particular scenario. Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other jurisdictions. Due to the provisions in PA 341 Section 6t (4) regarding multistate IRPs, Northern States Power-Wisconsin and Indiana Michigan Power Company are intentionally excluded from the explicit requirement to model the outlined scenarios. However, the multistate utilities are encouraged to include the provisions included in each scenario. The Commission may request additional information from multistate utilities prior to approving an IRP pursuant to Section 6t (4) of PA 341.

Scenario 1. Business as Usual

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7)

The existing generation fleet (utility and non-utility owned) is largely unchanged apart from new units planned with firm certainty or under construction. No carbon regulations are modeled, although some reductions are expected due to age-related coal retirements and renewable additions driven by renewable portfolio standards and goals, as well as economics.

- Natural gas prices utilized are consistent with business as usual projections as projected in the United States Energy Information Administration's (EIA) most recent Annual Energy Outlook reference case.[21]
- Footprint-wide[22] demand and energy growth rates remain at low levels with no notable drivers of higher growth; however, as a result of low natural gas prices, industrial production and industrial demand increases.
- Low natural gas prices and low economic growth reduce the economic viability of other generation technologies.
- Resource assumptions:
    - o Resources outside MI – Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO).
    - o Resources within MI – Thermal and nuclear generation retirements in the modeling footprint are driven by a maximum age assumption, public announcements, or economics.
- Specific new units are modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON) or signed generator interconnection agreement (GIA)).

[21] The natural gas price forecast utilized should be consistent with the EIA's most recent Annual Energy Outlook natural gas spot price at Henry Hub in nominal dollars and also including delivery costs from Henry Hub to the point of delivery.

[22] Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State of Michigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.

- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).
- For all instate electric utilities that are eligible to receive the financial incentive mechanism for exceeding mandated energy saving targets of 1% per year, EWR should be based upon the maximum allowed under the incentive of 1.5% and should be based upon an average cost of MWh saved. The model should include an EWR supply cost curve to project future program expenditures beyond baseline assumptions without any cap.[23]
- For all other electric utilities, EWR should not exceed the mandated targets for electric energy savings of 1% per year and should be based upon an average cost of MWh saved.
- Existing renewable energy production tax credits and renewable energy investment tax credits continue pursuant to current law.
- Technology costs for thermal units and wind track with mid-range industry expectations.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by their respective potential studies.
- Technology costs for solar and other emerging technologies decline with commercial experience.
- Existing PURPA contracts are assumed to be renewed.

Business as Usual Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period.[24]

2. Load projections
   (a) High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the business as usual load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.
   (b) If the utility has retail choice load in its service territory, model the return of 50% of its retail choice load to the utility's capacity service by 2023.

[23] For EWR cost supply curves, see the appendices in the supplemental potential study for the Lower Peninsula at this link: http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf.
[24] For example, 200% of the most recent EIA AEO reference case natural gas price is $10.14/MMBtu ($2016) in 2040.

3. Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in the Appendix G of the 2017 supplemental potential study for more aggressive potential.[25] EWR savings remain high throughout the study period.

4. Sensitivity allowing only natural gas fired simple cycle combustion turbines to be selected by the model.

[25] For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf; See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

Scenario 2. Emerging Technologies

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7)

Technological advancement and economies of scale result in a 35% reduction in costs for demand response, EWR programs, and other emerging technologies.[26] For example, costs identified in the demand response potential study should be reduced by 35% for demand response resources. No carbon reductions are modeled, but some reductions occur due to coal unit retirements, and higher levels of renewables, demand response, and energy waste reduction. Load forecasts and fuel price forecasts remain at levels similar to the Business as Usual Scenario.

- Technological advancement and economies of scale result in a greater potential for demand response, energy efficiency, and distributed generation as well as lower capital cost for renewables.
- Thermal generation retirements in the market are driven by unit age-limits and announced retirements (consistent with business as usual). Company-owned resource retirements may be defined by the utility, however, a meaningful analysis of whether coal units should retire ahead of business as usual dates should be performed. Retirements of all coal units except the most efficient in the utility's fleet should be considered, and those coal units owned by the utility that are not explicitly assumed to retire during the study period shall be allowed to retire in the model based upon economics. Retirement of older fuel oil-fired generation should also be considered in this scenario. Units that are not owned by the utility shall not retire during the study period unless affirmative, public statements to that effect are made by the owner of the generation asset.
- Specific new generating units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation interconnection queue.
- Prior to and during the modeling process, the utilities shall take into account resources that include, but are not limited to: small qualifying facilities (20 MW and under), renewable energy independent power producers, large combined heat and power plants, and self-generation facilities such as behind-the-meter-generation (btmg) as more fully described in section IX, Michigan IRP Modeling Input Assumptions and Sources.
- Existing renewable energy production tax credits and renewable energy investment tax credits continue pursuant to current law.
- Technology costs for thermal units remain stable and escalate at moderate escalation rates.
- Technology costs for EWR and demand response programs will be reduced 35% from the level determined by their respective potential studies.

[26] Emerging technologies includes, but is not limited to large-scale and small-scale battery storage, large-scale and small-scale solar, and combined heat and power. See Section IX, Michigan IRP Modeling Input Assumptions and Sources in this document for a full list of potential emerging technologies also could be considered to include as resources with reduced costs in this scenario.

- Technology costs for energy storage resources decline over time, particularly battery technologies and others which can enable supply- and demand-side resources.
- Existing PURPA contracts are assumed to be renewed.

Emerging Technologies Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period. [27]

2. Load projections
   (a) High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.

3. Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in Appendix G of the 2017 supplemental potential study for more aggressive potential.[28] EWR savings remain high throughout the study period.

4. Increase the use of renewable energy in the utility's service territory to at least 25% by 2030.

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[27] For example, 200% of the most recent EIA AEO reference case natural gas price is $10.14/MMBtu ($2016) in 2040.

[28] For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf; See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

Scenario 3. Environmental Policy

(Applicability: Utilities located in MISO Zone 7)

Carbon regulations targeting a 30% reduction (by mass for existing and new sources) from 2005 to 2030 across all aggregated unit outputs are enacted, modeled as a hard cap on the amount of carbon emissions, driving some coal retirements and an increase in natural gas reliance. Increased renewable additions are driven by renewable portfolio standards and goals, economics, and business practices to meet carbon regulations.

- Demand and energy growth rates are modeled at a level equivalent to a 50/50 forecast and are consistent with the business as usual projections.
- Natural gas prices utilized are consistent with business as usual projections as projected in the EIA's most recent Annual Energy Outlook reference case.[29]
- Current demand response, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they are economically selected by the model to help comply with the specified carbon reductions in this scenario.
- Non-nuclear, non-coal generators will be retired in the year the age limit is reached and driven by announced retirements. Coal units will primarily be retired based upon carbon emissions and secondarily based upon economics. Nuclear units are assumed to have license renewals granted and remain online.
- Specific new units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Tax credits for renewables continue until 2022 to model existing policy.
- Technology costs for wind, solar and other renewables decline with commercial experience and forecasted at levels 35% lower than in the business as usual case.
- Non-carbon dioxide emitting resources will be increased, due to the constraint on allowable carbon emissions in the model.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by their respective potential studies.
- Existing PURPA contracts are assumed to be renewed.
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).

[29] The natural gas price forecast utilized should be consistent with the EIA's most recent Annual Energy Outlook natural gas spot price at Henry Hub in nominal dollars and also including delivery costs from Henry Hub to the point of delivery.

Environmental Policy Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to at least 200% of the business as usual natural gas fuel price projections at the end of the study period. [30]

2. Load projections
   High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the base load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.

3. 50% carbon reduction in the utility's service territory, modeled as a hard cap on the amount of carbon emissions, by 2030 as a sensitivity.

4. Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in the 2017 supplemental potential study for more aggressive potential.[31] EWR savings remain high throughout the study period.

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[30] For example, 200% of the most recent EIA AEO reference case natural gas price is $10.14/MMBtu ($2016) in 2040.

[31] For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf; See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

Scenario 4. High Market Price Variant

(Applicability: Utilities located in the Michigan portion of MISO Zone 2)

An increase in economic activity drives higher than expected energy market prices. The existing generation fleet is largely unchanged apart from new units planned with firm certainty or under construction. No carbon regulations are modeled, though some reductions are expected due to age-related coal retirements and renewable additions driven by renewable portfolio standards and goals, as well as economics.

- Natural gas prices utilized are higher than business as usual projections and are consistent with projections in the EIA's most recent Annual Energy Outlook low oil and gas resource technology case[32] where natural gas prices near historical highs drive down domestic consumption and exports.
- Footprint-wide[33] demand and energy growth rates are moderate to robust with notable drivers of higher growth.
- High natural gas prices and moderate to robust economic growth increase the economic viability of alternative technologies.
- Thermal generation retirements in the market are driven by unit age-limits, and announced retirements are driven by age and environmental regulations. Company-owned resource retirements are defined by the utility.
- Specific new generating units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation interconnection queue.
- Tax credits for renewables continue until 2022 to model existing policy.
- Technology costs for thermal units remain stable and escalate at low to moderate escalation rates.
- Technology costs for renewables remain stable and escalate at low to moderate escalation rates.
- Technology costs for energy efficiency and demand response remain stable and escalate at low to moderate escalation rates.
- Existing PURPA contracts are assumed to be renewed.

High Market Price Variant Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base scenario projections to at least 150% of the natural gas price forecast at the end of the study period.

[32] The natural gas price forecast utilized should be consistent with the EIA's most recent Annual Energy Outlook natural gas spot price at Henry Hub in nominal dollars and also including delivery costs from Henry Hub to the point of delivery.

[33] Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State of Michigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.

(b) Reduce natural gas fuel price projections to half of the natural gas fuel projections used in this scenario.

2. Load projections
   (a) High load growth: Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates. In the event that doubling the energy and demand growth rates results in less than a 1.5% spread between the business as usual load projection and the high load sensitivity projection, assume a 1.5% increase in the annual growth rate for energy and demand for this sensitivity.
   (b) If the utility has retail choice load in its service territory, model the return of 50% of its retail choice load to the utility's capacity service by 2023.

3. Grid defection: Reduced load due to the development of residential small cogeneration units, solar, batteries, and wind could influence more customers going "off-grid" as electric rates continue to be high in the Upper Peninsula.

4. Ramp up the utility's EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in the 2017 supplemental potential study for more aggressive potential. EWR savings remain high throughout the study period.[34]

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[34] For maximum achievable potential levels, see the supplemental potential study for the Lower Peninsula, http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf; See also supplemental potential study for the Upper Peninsula, http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx.

IX. Michigan IRP Modeling Input Assumptions and Sources

The following IRP modeling input assumptions and sources are recommended to be used in conjunction with the descriptions of the scenarios and sensitivities.

	Value	Sources
1 - Analysis Period	• A minimum analysis period of 20 years, with reporting for years 5,10, and 15 at a minimum as specified in the statute.	
2 - Model Region	•The minimum model region includes the utility's service territory, with transmission interconnections modeled to the remainder of Michigan, adjacent Canadian provinces if applicable. A larger model region is preferable, including the applicable RTO region as deemed appropriate by utility.	
3 - Economic Indicators and Financial Assumptions (e.g. Weighted Average Cost of Capital)	• Utility-specific	• Prevailing value from most recent MPSC proceedings
4 - Load Forecast	• 50/50 forecast • Forecasts other than 50/50 utilized to align with scenario and/or sensitivity descriptions should be documented and justified.	• Utility forecast and applicable RTO forecasts
5 - Unit Retirements	• Retirements driven by maximum age assumption or economics • Public announcements on retirements	• MISO or PJM documented fuel type retirements • All retirement assumptions must be documented
6 - Natural Gas Price *nominal dollars $/MMBtu*	• Forecasts utilized should align with scenario and/or sensitvity descriptions; Gas prices should include transportation costs.	• NYMEX futures (applicable for near-term forecasts only) • EIA Annual Energy Outlook • EIA Table 3: Energy Prices • EIA Short-Term Energy Outlook Reports • If utility-specific data is utilized, it should be justified and made available to all intervening parties.
7 - Coal Price *nominal dollars $/MMBtu*	• Forecasts utilized should align with scenario and/or sensitvity descriptions; Coal prices should include transportation costs.	• EIA Coal Production and Minemouth Prices by Region • EIA Annual Energy Outlook • EIA Table 3: Energy Prices • EIA Short-Term Energy Outlook Reports/Annual Reports • If utility-specific data is utilized, it should be justified and made available to all intervening parties.
8 - Fuel Oil Price *nominal dollars $/MMBtu*	• Forecasts utilized should align with scenario and/or sensitvity descriptions.	• If utility-specific data is utilized, it should be justified and made available to all intervening parties.
9 - Energy Waste Reduction Savings *MWhs*	Business as Usual Scenario: • For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to load forecast. • For non-incentive earning electric utility, mandated annual incremental savings (1.0%) as a net to load. • Not less than 35% of the state's electric needs should be met through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3). EWR Business as Usual Sensitivities: • For savings beyond mandate, incorporate EWR as an optimized generation resource. Emerging Technologies Scenario: • Ramp up EWR savings at least 2.5% over the course of four years, using EWR Cost Supply Curves provided in the 2017 Supplemental Potential Study for More Aggressive Potential (e.g., with 100% incremental cost of incentives, no cost cap and emerging technologies assumptions.) • Consider load shape of EWR measures so on-peak capacity reduction associated with EWR can be reflected.	• Utility EWR plan and reconciliation filings • 2016 EWR Potential Studies for Consumers Energy and DTE Energy • 2017 Lower Peninsula EWR Basic Potential Estimate • 2017 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential • 2017 Lower Peninsula EWR Cost Supply Curves

10 - Energy Waste Reduction Costs *nominal dollars per kWh* *(Program administrator costs only; participant costs are not to be included in this analysis.)*	• Current average levelized costs as defined in 2016/2017 Potential Studies and Supplemental Modeling reflecting aggressive and cost effective program savings goals.	• 2016 EWR Potential Studies for Consumers Energy and DTE Energy • 2017 Lower Peninsula EWR Basic Potential Estimate • 2017 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential • 2017 Lower Peninsula EWR Cost Supply Curves
11 - Demand Response Savings *MWs*	• MWs by individual program (e.g., residential peak pricing, residential time-of-use pricing, residential peak time rebate pricing, residential programmable thermostats, residential interruptible air, industrial curtailable, industrial interruptible, etc.) or program type and class (e.g., residential behavioral, residential direct control, commercial pricing, volt/VAR optimization). • Technical, economic and achievable levels of demand response as applicable to the scenario.	• As defined by 2017 Demand Response Potential Study
12 - Demand Response Costs *nominal dollars per MW*	• Costs/MW by program including all payments, credits, or shared savings awarded to the utility through regulatory incentive mechanism.	• As defined by 2017 Demand Response Potential Study
13 - Renewable Capacity Factors		• If utility-specific data is utilized, it should be justified and made available to all intervening parties.
14 - Renewable Capital Costs and Fixed O&M Costs *nominal dollars per kWh* *and* **Renewable Fixed O&M Costs** *nominal dollars per kW*	• Wind, solar, biomass, landfill gas • Combined heat and power (CHP)	• National Renewable Energy Lab's *Annual Technology Baseline Report* • Department of Energy's *Wind Technologies Market Report* • Lawrence Berkeley National Lab's *Tracking the Sun* and *Utility Scale PV Cost* • Assumptions based on utility experience (Michigan specific and/or RTO - MISO/PJM) • 2015 Michigan Renewable Resource Assessment • Department of Energy's *Wind Vision Study* • Department of Energy's *Sunshot Vision Study* • Lazard's Levelized Cost of Storage Analysis 2.0 • If utility is using specific data not publicly sourced, must be justified and made available to all intervening parties.
15 - Other/Emerging Alternatives	• Changes to operation guides • Options which improve reliability (SVC, HVDC, volt/VAR) • Utilities shall take into account small qualifying facilities (20 MW and under) and other aggregated demand-side options as part of establishing load curves and future demand. Larger renewable energy resources, combined heat and power plants, and self-generation facilities (behind-the-meter generation) that consist of resources listed below or fossil fueled generation should be considered in modeling, either as discrete projects where such have been developed/defined, or as generic blocks of tangible size (e.g., 100 MW wind farm) where not yet defined. • Utility-scale (e.g., integrated gasification combined cycle, combined heat and power, pumped hydro storage, voltage optimization) • Behind-the-Meter (customer BTM) Generation (e.g., solar photovoltaic (PV), biogas (including anaerobic digesters), combined heat and power (combustion turbine, steam, reciprocating engines), customer-owned backup generators, microturbines (with and without cogeneration), fuel cells (with and without cogeneration), small-scale RICE units (with and without cogeneration)) • Other Distributed Resources (e.g., stationary batteries, electric vehicles, thermal storage, compressed air, flywheel, solid rechargeable batteries, flow batteries).	• Assumptions and parameters other than costs that are associated with the technologies and options (such as future adoption rates) should be afforded flexibility due to those technologies' and options' presently unconventional nature. However, the utility should still show that all assumptions and parameters are reasonable and were developed from credible sources. • Utilities shall use cost and cost projection data from publicly available sources or the utility's internal data sources. The utility must show that their data and projection sources are reasonable and credible.
16 - Wholesale Electric Prices		• Documentation for wholesale price forecast must be provided to all intervening parties.

X. Additional IRP Requirements and Assumptions

1. Utility-specific assumptions for discount rates, weighted average cost of capital and other economic inputs should be justified and the data shall be made available to all parties.

2. Prices and costs should be expressed in nominal dollars.

3. The capacity import and export limits in the IRP model for the study horizon should be determined in conjunction with the applicable RTOs and transmission owners resulting from the most current and planned transmission system topology. Deviations from the most recently published import and export limits should be explained and justified within the report.

4. Environmental benefits and risk must be considered in the IRP analysis.

5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, as well as storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled over the planning period. Factors such as geographic location with respect to wind or solar resources and data sources that focus specifically on renewable resources should be considered in the determination of initial capital cost and production cost (life cycle/dispatch).

6. Models should account for operating costs and locational, capital and performance variations. For example, setting pricing for different tranches if justified.

7. Capacity factors should be projected based on demonstrated performance, consideration of technology improvements and geographic/locational considerations. Additional requirements for renewable capacity factors are described in the Michigan IRP Modeling Input Assumptions and Sources in the previous section of this draft.

8. The IRP model should optimize the incremental EWR and renewable energy to achieve the 35% goal. However, the model should not be arbitrarily restricted to a 35% combined goal of EWR and renewable energy. Exceeding the combined EWR and renewable energy goal of 35% by 2025 shall not be grounds for determining that the proposed levels of peak load reduction, EWR and renewable energy are not reasonable and cost effective.

9. For purposes of IRP modeling, forecasted energy efficiency savings should be aggregated into hourly units, coincident with hourly load forecasts, with indicative estimates of efficiency cost and savings on an hourly basis. It is this aggregation and forecast of energy efficiency, to be acquired on an hourly basis that allows EWR to be modeled as a resource in an IRP for planning purposes.

10. Prior to modeling the Business as Usual, Emerging Technologies, Environmental Policy, or High Market Price Variant Scenarios, the utilities shall consider and prescreen all of the technologies, resources, and generating options listed in the Michigan IRP Modeling Input

Assumptions and Sources in the previous section of this draft. These findings will then be presented and discussed via at least one stakeholder meeting with written comments from stakeholders taken into consideration. The options having potential viability are then considered in modeling.

11. Consider including transmission assumptions in the IRP portfolio, such as the impact of transmission and non-transmission alternatives (local transmission, distribution planning, locational interconnection costs, environmental impacts, right of way availability and cost) to the extent possible.

12. Consider all supply and demand-side resource options on equal merit, allowing for special consideration for instances where a project or a resource need requires rapid deployment.

13. In modeling each scenario and sensitivity evaluated as part of the IRP process, the utility shall clearly identify all unit retirement assumptions and unless otherwise specified in the *required* scenarios, the utility has flexibility to allow the model to select retirement of the utility's existing generation resources, rather than limiting retirements to input assumptions.

14. Recognize capacity and performance characteristics of variable resources.

15. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.

16. Take into consideration existing power purchase agreements, green pricing and/or other programs.

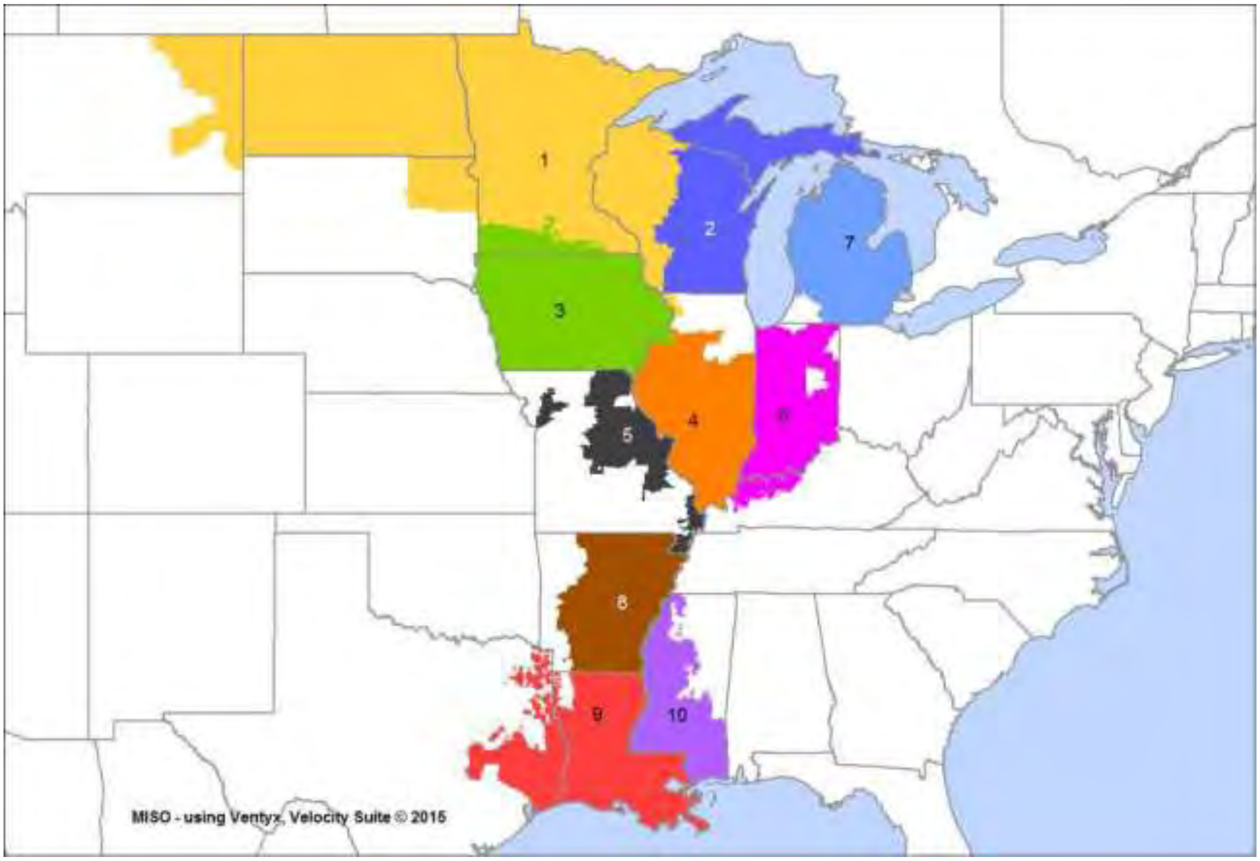
17. The IRP should consider any and all revenues expected to be earned by the utility's asset(s), as offsets to the net present value of revenue requirements.

18. An analysis regarding how incremental investments would compare to large investments in specific technologies that might be obsolete in a few years.

Appendix A: Organization Participation List: The workgroups consisted of people from the following organizations or groups:

1. ACEEE
2. American Transmission Company (ATC)
3. CLEAResult
4. Cloverland Electric Cooperative
5. Consumers Energy Company
6. DTE Electric Company
7. Ecology Center
8. EcoWorks et al.
9. Energy Storage Association
10. Environmental Law and Policy Center
11. 5 Lakes Energy
12. Indiana Michigan Power Company (I&M)
13. Institute for Energy Innovation
14. ITC Holdings (ITC)
15. Lawrence Berkeley National Laboratory
16. Michigan Agency for Energy (MAE)
17. Michigan Biomass
18. Michigan Chemistry Council
19. Michigan Department of Environmental Quality (MDEQ)
20. Michigan Electric and Gas Association (MEGA)
21. Michigan Energy Innovation Business Council
22. Michigan Environmental Council (MEC)
23. Michigan Municipal Electric Association (MMEA)
24. Michigan Public Service Commission (MPSC)
25. Midland Cogeneration Venture (MCV)
26. Midwest Energy Efficiency Alliance
27. National Housing Trust
28. National Regulatory Research Institute (NRRI)
29. Natural Resources Defense Council (NRDC)
30. Northern Michigan University
31. Public Sector Consultants (PSC)
32. Public Law Resource Center
33. Residential Customer Group
34. Union of Concerned Scientists
35. UP Association of County Commissioners Energy Task Force
36. Upper Peninsula Power Company (UPPCO)
37. Upper Michigan Energy Resources Corporation (UMERC)
38. Varnum LLP
39. Wind on the Wires
40. Wolverine Power Supply Cooperative (Wolverine)
41. WPPI Energy (WPPI)

Appendix B: Map of MISO Local Resource Zones



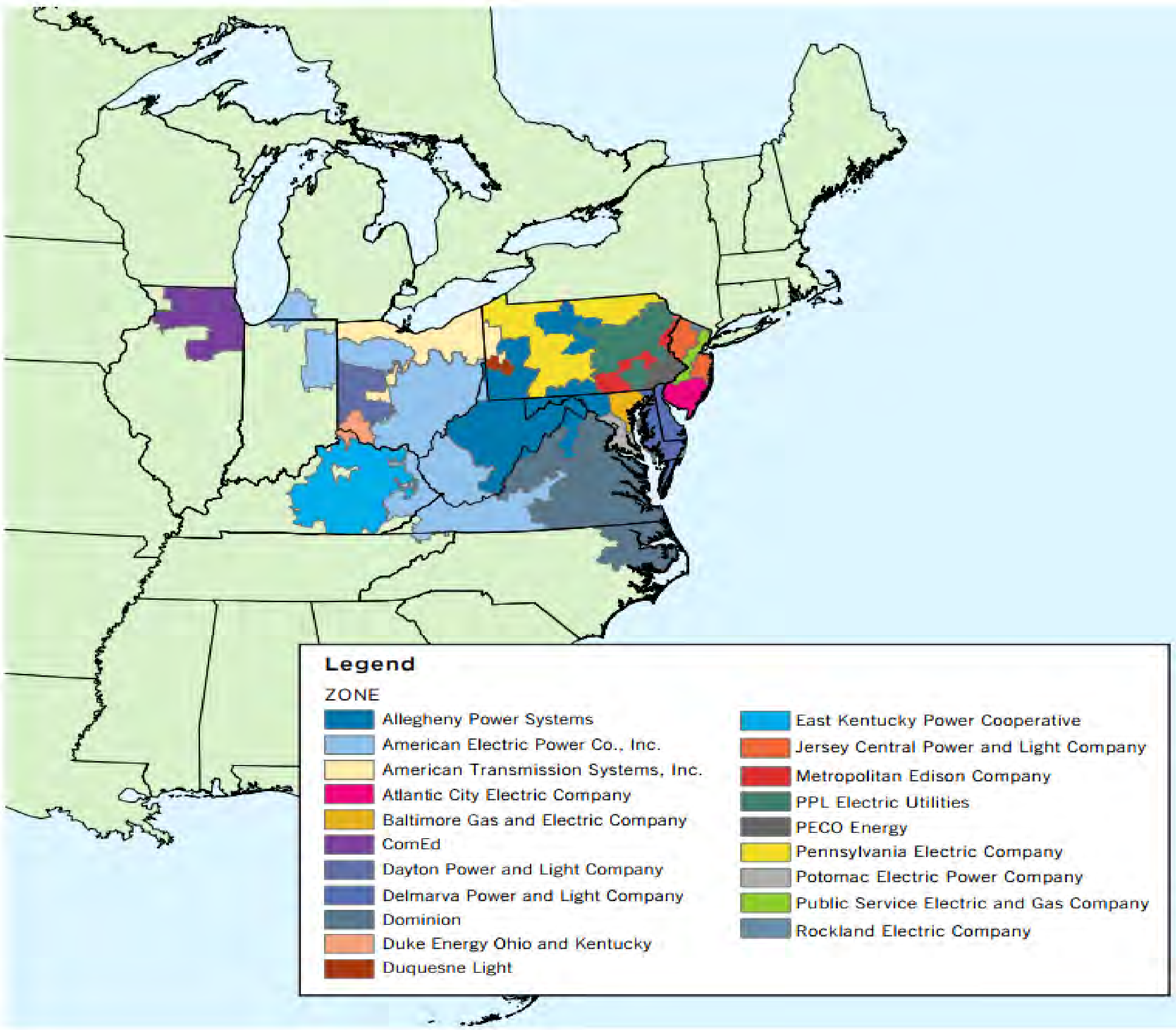
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

MISO Zone 2 - Rate regulated electric utilities - Upper Michigan Energy Resources Corporation and Upper Peninsula Power Company

MISO Zone 7 - Rate regulated electric utilities - Alpena Power Company, Consumers Energy Company, and DTE Electric Company

PJM (Southwest Michigan) - Rate regulated electric utility - Indiana Michigan Power Company

Appendix C: Map of PJM Local Deliverability Areas



PJM (Southwest Michigan) - Rate regulated electric utility - Indiana Michigan Power Company is part of the American Electric Power Co., Inc.

Appendix D: Public Act 341 of 2016, Section 6t (1)

Section 6t (1) The commission shall, within 120 days of the effective date of the amendatory act that added this section and every 5 years thereafter, commence a proceeding and, in consultation with the Michigan agency for energy, the department of environmental quality, and other interested parties, do all of the following as part of the proceeding:

(a) Conduct an assessment of the potential for energy waste reduction in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable.

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

(c) Identify significant state or federal environmental regulations, laws, or rules and how each regulation, law, or rule would affect electric utilities in this state.

(d) Identify any formally proposed state or federal environmental regulation, law, or rule that has been published in the Michigan Register or the Federal Register and how the proposed regulation, law, or rule would affect electric utilities in this state.

(e) Identify any required planning reserve margins and local clearing requirements in areas of this state.

(f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:

  (i) Any required planning reserve margins and local clearing requirements.

  (ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.

  (iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, and projected load management and demand response savings.

  (iv) Any regional infrastructure limitations in this state.

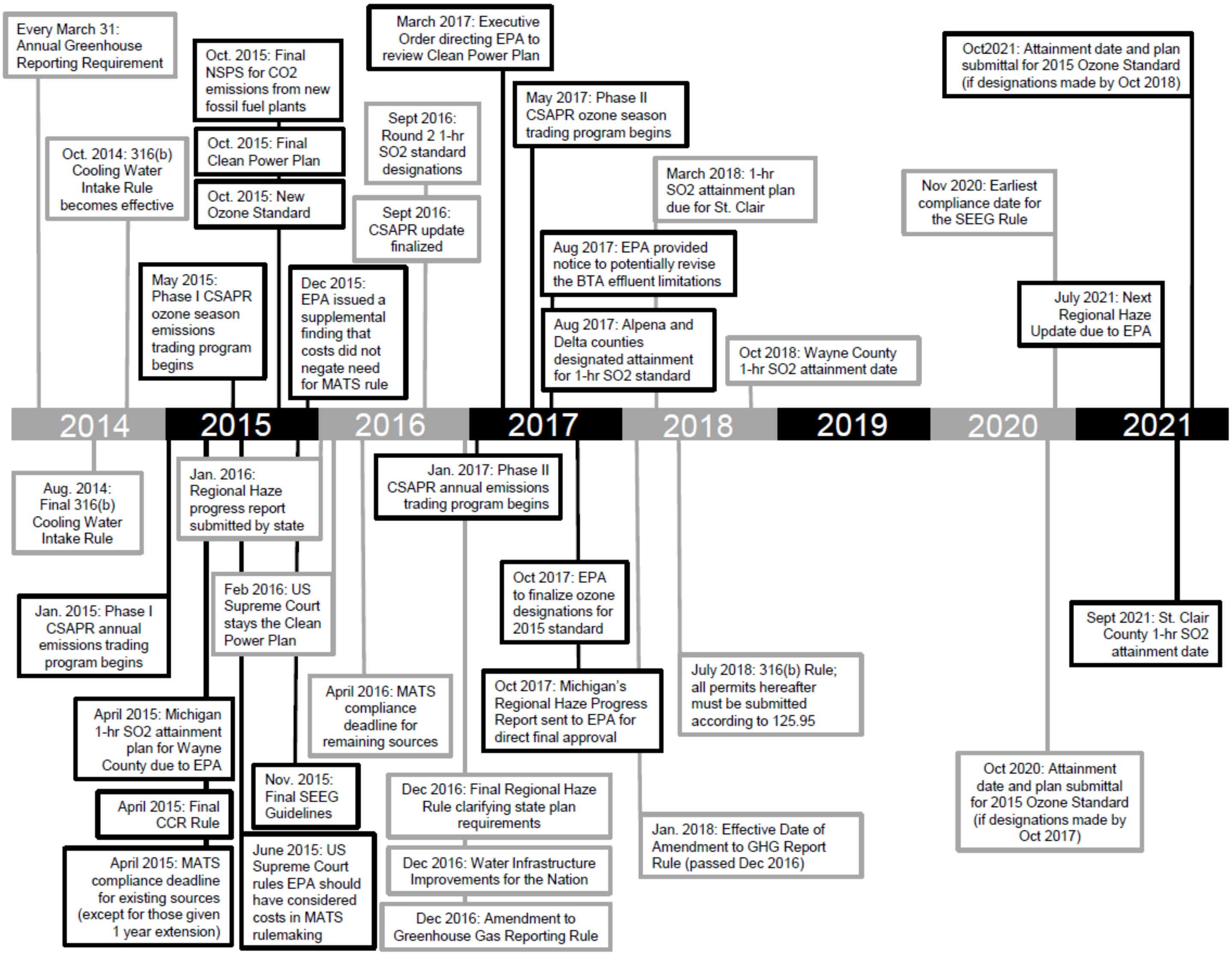
  (v) The projected costs of different types of fuel used for electric generation.

(g) Allow other state agencies to provide input regarding any other regulatory requirements that should be included in modeling scenarios or assumptions.

(h) Publish a copy of the proposed modeling scenarios and assumptions to be used in integrated resource plans on the commission's website.

(i) Before issuing the final modeling scenarios and assumptions each electric utility should include in developing its integrated resource plan, receive written comments and hold hearings to solicit public input regarding the proposed modeling scenarios and assumptions.

Appendix E: Environmental Regulatory Timeline



P R O O F O F S E R V I C E

STATE OF MICHIGAN)

Case No. U-18418

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on November 21, 2017 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Lisa Felice

Lisa Felice

Subscribed and sworn to before me
this 21st day of November 2017

Steven J. Cook

Steven J. Cook
Notary Public, Ingham County, Michigan
As acting in Eaton County
My Commission Expires: April 30, 2018

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Updated 8-18-2017

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Updated 8-18-2017

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Updated 8-18-2017

Attachment B

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to implement the provisions of Section 6s of 2016 PA 341.	)	Case No. U-15896
In the matter, on the Commission's own motion, to implement the provisions of Section 6t of 2016 PA 341.	)	Case No. U-18461

At the December 20, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

OPINION AND ORDER

On December 21, 2016, Public Act 341 of 2016 (Act 341), an amendment to Public Act 3 of 1939 and Public Act 286 of 2008, was signed into law and became effective on April 20, 2017. Section 6t(3) of Act 341, MCL 460.6t(3), requires that each electric utility, whose rates are regulated by the Commission, file an integrated resource plan (IRP) within two years from the effective date of Act 341. Section 6t(3) states that 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." And, Section 6t(6) provides, in part, that:

> An existing supplier of electric generation capacity currently producing at least 200 megawatts of firm electric generation capacity resources located in the independent system operator's zone in which the utility's load is served that seeks to provide electric generation capacity resources to the utility may submit a written proposal directly to the commission as an alternative to any supply-side generation capacity resource included in the electric utility's integrated resource plan submitted under this section . . . .

In addition, pursuant to Section 6s(4)(a), the Commission must grant a certificate of necessity (CON) to an electric utility if it finds, among other determinations, 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)."

The Commission Staff (Staff) worked with various stakeholders to prepare draft Application Instructions for Integrated Resource Plan Filings (IRP filing instructions) and draft Instructions for Certificate of Necessity Alternative Proposals for Electric Generation Capacity Resources (alternative proposals) pursuant to Sections 6s and 6t of Act 341.

In the October 11, 2017 order in Case No. U-18461, the Commission requested comments on the proposed IRP filing requirements and alternative proposals from all interested persons. The Commission received comments from nine organizations, which are discussed pursuant to the applicable headings set forth in the IRP filing requirements and alternative proposals and are addressed *ad seriatim*. Sections of the IRP filing requirements and alternative proposals for which no comments were received are undisputed and have been omitted from the following discussion. Although no comments were received on this issue, the Commission notes that for purposes of clarity, several minor grammatical and stylistic amendments were made to the IRP filing requirements and alternative proposals.

Application Instructions for Integrated Resource Plan Filings

The Commission notes that the Application Instructions for IRP filings also apply to an IRP filed with a CON application and that the correlating statute was inadvertently omitted from the instructions. In addition, the Commission concludes that footnote 2 is overly specific for general IRP application instructions. Therefore, the Commission amends the first paragraph as follows:

> These application instructions apply to a standard electric utility application for Michigan Public Service Commission (~~MPSC or~~ Commission) approval of an Integrated Resource Plan (IRP) under the provisions of MCL 460.6t**, as well as an IRP that may be filed under the provisions of MCL 460.6s**.[1] The application shall be consistent with these instructions, with each item labeled as set forth below.~~[2]~~ Any additional information considered relevant by the utility may also be included in the application.
>
> ~~[2] Indiana Michigan Power Company (I&M) plans to file a single, total company IRP covering all of its customers in Indiana and Michigan with both the IURC and MPSC. Consistent with MCL 460.6t (4) for purposes in Michigan, I&M will prepare its 2018 IRP and subsequent IRPs in accordance with the requirements of the Indiana IRP Rules.~~

Schedule

Section 6t(3) of Act 341 requires, in part, that the Commission "issue an order establishing the filing requirements . . . and filing deadlines for an integrated resource plan filed by an electric utility whose rates are regulated by the commission." In compliance with Act 341, the Commission finds that the IRP application filing deadlines are more appropriately set forth in this order, rather than the IRP filing requirements. Therefore, the IRP application filing deadlines are removed from the IRP filing requirements and set forth below. Additionally, in order to more efficiently balance its workload, the Commission has slightly adjusted the IRP application filing deadlines that were set forth in the previous draft of the IRP filing requirements.

In response to an undisputed request by DTE Electric Company (DTE Electric), to the currently-noted schedule, the Commission adds the words, "or earlier date if requested and spaced at least 21 days from other IRP filings." The updated schedule is as follows:

1. Consumers Energy Company: June 15, 2018 (or earlier date if requested and spaced at least 21 days from other IRP filings)

2. Upper Peninsula Power Company: October 1, 2018 (or earlier as requested)

3. Indiana Michigan Power Company: within forty-five (45) days of submission in its Indiana jurisdiction to align with the Indiana filing schedule (Indiana jurisdiction filing is due November 1, 2018)

4. Northern States Power Company-Wisconsin (Xcel): January 25, 2019 (or to align with Minnesota)

5. Alpena Power Company: February 15, 2019

6. Upper Michigan Energy Resources Corporation: March 8, 2019

7. DTE Electric Company: March 29, 2019 **(or earlier date if requested and spaced at least 21 days from other IRP filings)**

8. Wisconsin Electric Power Company: April 19, 2019

Pre-Filing Request for Proposals

DTE Electric comments that requests for proposals (RFPs) for small capacity resources and renewable energy (RE) resources governed by 2008 PA 295 (Act 295) should be exempt from the IRP filing requirements. The company requests that the following language be added to this section: "Each electric utility whose rates are regulated by the Commission shall issue a request for proposals (RFP) to provide any new **greater than 50 MW [megawatts], non-renewable** supply-side capacity resources . . . ." DTE Electric's initial comments, p. 1 (emphasis in original).

The Commission declines to adopt DTE Electric's proposed language because Act 341 does not set forth an exemption for small capacity and RE resources governed by Act 295. In addition, it is beneficial for a utility to receive updated costs for RE, including solar and battery storage that may be less than 50 MW, and issuing an RFP is a useful way for a utility to garner this information.

The Commission notes that, under the current language of this section, a utility has the ability to exclude a long-term power purchase agreement (PPA) from the RFP process. To avoid this type of restriction, the Commission adds the following language to the end of the section:

> e) The RFP shall allow for proposals to provide new supply-side capacity in the form of a purchase power agreement for a period that is the lesser of the study period or of the useful life of the resource type proposed.

Public Outreach Process

DTE Electric and Consumers Energy Company (Consumers) request that the words "including senior executives" be removed from the first paragraph. DTE Electric argues that utilities "should have the flexibility to determine the appropriate internal company employees to engage in the stakeholder processes based on the expertise and specific analysis involved in a particular IRP filing." DTE Electric's comments, p. 1. This recommendation is undisputed, and therefore, the Commission adopts the proposed amendment.

The Association of Businesses Advocating Tariff Equity (ABATE) comments that the IRP filing requirements, as written, "encourage" utilities to engage participants early in the IRP process. ABATE's initial comments, p. 1. However, ABATE recommends that the Commission *require* participant engagement prior to the filing of the IRP. ABATE explains that "Additional perspectives, coupled with the free-flow of information, only serve to amplify the benefits of an IRP. The Commission can ensure an open and transparent process by using mandatory language throughout this section." *Id.* The Union of Concerned Scientists (UCS) agrees, and asserts that the Commission should permit public comments on a proposed IRP without having to establish formal intervenor status.

DTE Electric and Consumers respond that requiring public outreach and analysis of every potential scenario and input could result in a lengthy and costly process of analytical runs. They request that the stakeholder input process remain flexible in its scope and implementation, asserting that Commission encouragement of public outreach is sufficient to ensure open and transparent communication with the public. In addition, DTE Electric contends that "there are mandatory processes for input associated with the contested IRP and CON cases that will be required in the future." DTE Electric's reply comments, p. 1.

The Commission notes that there is no requirement in Act 341 mandating that the utilities host stakeholder and public outreach workshops. However, the Commission believes that stakeholder and public engagement are critically important to the IRP process in order to provide stakeholders and the public an opportunity to supply input regarding the utility's assumptions, inputs, and modeling methodologies. The Commission amends the language of this section as follows:

> Participant engagement early in the development of the IRP is **strongly** encouraged~~,~~ to**:** (1) educate potential participants on utility plans; (2) utilize a transparent decision making process for resource planning; (3) create opportunity to provide feedback to the utility~~, including senior executives,~~ on its resource plan; (4) encourage robust and informed dialogue on resource decisions; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.
>
> In the **12 months** ~~365 days~~ prior to the IRP filing, each electric utility **is encouraged** ~~shall consider~~ **to** host~~ing~~ update workshops with interested participants. The purpose of the pre-filing workshop(s) is to ensure that participants have the opportunity to provide input and stay informed regarding**:** **(**1) the assumptions, scenarios, and sensitivities~~,~~**;** **(**2) the progress of the utility's IRP process~~,~~**;** and **(**3) plans for the implementation of the proposed IRP. Documentation may include:
>
> a) Workshop dates and times, including times outside of the workday;
> b) Evidence that notice of the workshops was provided to the public;
> c) Meeting minutes;
> d) Meeting or workshop attendance lists;

e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application; and
f) Discussion indicating if or how the public outreach process influenced the IRP.

A minimum of two stakeholder engagement workshops are recommended. A stakeholder engagement workshop will provide stakeholders with an opportunity to provide input regarding the utility's assumptions, inputs, and modeling methodologies employed during the development of the IRP. The utility is encouraged to invite stakeholders, including expected intervenors and the Staff, to its stakeholder engagement workshops.

If the stakeholder engagement workshops are not open to the public, two additional public meetings are recommended. The public meetings are intended to educate the public on the utility's planning process as well as provide an opportunity for the public to comment. The public meetings should be offered in the utility's service territory in geographic locations convenient to customers, with advance notice provided to customers in the utility's service territory. The utility is encouraged to consider holding public meetings after normal business hours to encourage attendance.

Risk Assessment Methodology

In the November 21, 2017 order in Case No. U-18418, the Commission stated that it would address the issue of risk assessment in the immediate case. To ensure that risk assessment scenarios are consistent between CON and IRP filings, the Commission amends the language in this section as follows:

> ~~Each~~ **The** utility's IRP filing shall include a thorough risk analysis of the preferred plan and the **optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the**~~ alternatives considered in the~~ IRP **application**. **The plans should be feasible and differ in generation mix from the preferred plan and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies for each scenario to determine how each strategy would perform in an unexpected range of possible futures.** The IRP shall include a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent-based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.

Without setting any further parameters, the Commission strongly recommends that the utilities perform robust risk analysis.

Approval of Costs

DTE Electric notes that there are separate filing and approval processes for RE and energy waste reduction (EWR) plans. The company argues that it is duplicative to approve these plans in the IRP as well. DTE Electric recommends a separate proceeding for the filing and approval of the initial plans and utilizing the IRP for approval of amendments to the plans.

ABATE does not oppose DTE Electric's recommendation; however, it requests that the Commission ensure congruency between known/approved costs and the costs for which a utility is seeking approval. "In other words, the inputs from a utility's IRP model(s) should align with the information provided in the Rate Impact and Financial Information section." ABATE's reply comments, p. 1. ABATE states that if the Commission removes the references to RE and EWR programs, the Commission should ensure that utilities provide "real-world costs" when available. *Id.*

Regarding the total demand reduction potential, including hourly shape of load reduction by program, Consumers notes that load reduction caused by demand response (DR) programs occurs on a daily four-hour peak. The company argues that running an hourly load shape would not be beneficial because the load reduction would be zero until the four-hour peak window is realized. According to Consumers, the DR hourly load shape is not similar to an energy efficiency hourly load shape because energy efficiency offsets sales throughout the day rather than reducing load during peak demand hours. Consumers' initial comments, p. 2.

The Commission declines to adopt DTE Electric's recommendation to utilize the "Renewable Resources" and "Demand Response and Energy Waste Reduction" subsections of the Approval of

Costs section for the limited purpose of approving RE and EWR plan amendments. The Commission finds that the purpose of the IRP is to determine the optimal future combination of RE, EWR, and DR, and should not be limited to what is already approved in RE, EWR, and DR plans. If a utility does not include RE and EWR as part of its IRP, the utility will not have the ability to select additional RE and EWR over and above what is already included in its approved plans. The Commission notes that separate RE and EWR plan cases may continue to be necessary to implement the specific RE and EWR programs and, if amendments to the plans are required, separate cases requesting Commission approval may need to be filed between utility IRPs.

In addition, the Commission finds that section II) Renewable Resources does not accurately reflect the language of 2016 PA 342. Therefore, it is amended as follows:

> II) Renewable Resources: **The utility shall file data consistent with its renewable energy plan. (For incremental renewable energy beyond the 15% requirement in 2021 and any renewable energy to be constructed or purchased after the conclusion of the 20-year renewable planning period ending in 2029, the utility shall file as set forth below.)** Revenue requirement and incremental costs of compliance shall be calculated to include the following:

In response to ABATE's concerns regarding congruency and "real-world costs," the Commission notes that the above-amended language addresses ABATE's concerns and that real-world costs are covered in the MIRPP.

The Commission agrees with Consumers and adopts the company's recommendation that the requirement for DR hourly load shapes should be removed from subsection b) in section III) Demand Response and Energy Waste Reduction. However, the Commission finds that utilities shall continue to provide the amount of load reduction and operational parameters. The Commission amends subsection b) as follows:

> Total demand reduction potential (MW), including **the amount of load reduction and the expected hours of interruption per day, month, and year for each program,** ~~including hourly shape of load reduction (MWh)~~ if applicable;

Waivers and Process for Smaller and Multistate Utilities

Michigan Electric and Gas Association (MEGA) affirms that the proposed language in the "Waivers and Process for Smaller and Multistate Utilities" section is authorized by MCL 460.6t(4). According to MEGA, the flexibility provided by the IRP filing requirements appropriately allows each utility to specifically tailor its initial IRP, and it avoids "unnecessary and duplicative administrative, legal and processing costs which must be borne by relatively few customers, compared to the major electric utilities." MEGA's initial comments, p. 2.

In its reply comments, Upper Peninsula Power Company (UPPCo) agrees with MEGA and expresses support for the language in this section.

After a review of UPPCo's reply comments, it occurs to the Commission that there is no deadline for a waiver application. If a utility requests a waiver in conjunction with the filing of its application, the Commission may be placed in the problematic position of either granting a waiver or rejecting the IRP. Therefore, the Commission amends the first paragraph as follows:

> **An** ~~E~~electric utilit**y**~~ies~~ with fewer than 1,000,000 customers in this state may request a waiver to any portion of these IRP filing requirements ~~with its IRP application~~. Any request for a waiver shall include a discussion and justification outlining why the waiver is warranted and in the best interest of its customers. Discussion and justification for the requested waiver shall include a description of the utility's current and forecasted energy and capacity needs, and its plan for meeting those needs over the upcoming ten years.
>
> **If the utility requires resolution of a waiver request prior to filing an IRP application, the utility shall file the waiver request no less than 60 days prior to the filing of the IRP application.**

UCS requests specific language stating that the Commission has the authority to request additional or supplemental information to facilitate the review of the utility's IRP as it relates to Michigan. There are no reply comments. The Commission agrees that additional information may be beneficial for the review of a multistate IRP. Therefore, the Commission adopts the following language:

> ~~Staff notes that~~ Northern States Power Company-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other jurisdictions. Due to the provisions in MCL 460.6t(4) regarding multistate IRPs, Northern States Power Company-Wisconsin and Indiana Michigan Power Company may utilize the IRP filing requirements of another state in accordance with those provisions. **However, the Commission reserves the right to request additional information to facilitate its review of the IRP as it relates to Michigan.**

<u>IRP Report and Documentation</u>

In general, DTE Electric states, there are various requirements that involve providing the utility's revenue requirement, existing resource revenue requirements, and revenue requirements by rate design. The company, however, opines that these requirements are more suitable for a rate case. DTE Electric believes that the IRP is "intended to focus on additions to the generation scope and revenue requirements should properly only reflect on the incremental costs of the new proposed generation resources." DTE Electric's initial comments, p. 1.

The Commission agrees that providing revenue requirements by rate design or by rate class is not appropriate in an IRP and is more suitable in a rate case. The Commission notes that all references to rate design and rate class have therefore been removed. However, the Commission finds that existing resources should be included in the revenue requirements because the types, sizes, and timing of proposed new generators may impact the dispatch of existing units, thereby impacting the revenue requirement in ways other than the added revenue requirement associated with the new resources.

1. Executive Summary

UCS comments that section I) Executive Summary should specifically include a description of the utility's anticipated changes in resource mix and corresponding changes in emissions of carbon dioxide, sulfur oxides, nitrogen oxides, particulate matter, mercury, and lead, as well as anticipated production of hazardous solid waste and wastewater discharges.

On page 4 of its reply comments, Consumers states that the Executive Summary is "intended to provide a high-level overview of the IRP analysis and proposed course of action, which considers environmental impacts. It is not necessary to overly prescribe the level of detail."

The Commission agrees with Consumers that the Executive Summary is intended to be just that: a summary. Details regarding the anticipated changes in resource mix and corresponding changes in environmental pollutants are covered in section XVIII) Environmental of the IRP filing requirements.

2. Introduction

Regarding section IV) Introduction, DTE Electric requests that the Commission amend the third sentence to read: "The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that ~~satisfy all of~~ **consider** the planning objectives and priorities." DTE Electric's initial comments, p. 1. There are no reply comments. The Commission adopts the proposed amendment because it more adequately demonstrates that the utility considered the planning objectives pursuant to Section 6t of Act 341.

In addition, DTE Electric notes that there is a requirement for annual levelized cost of generation portfolio. The company argues that the requirement is unclear in its intent and scope, and it may be burdensome to analyze. There are no reply comments. The Commission agrees with DTE Electric and removes this requirement.

3. Analytical Approach

Regarding section V) Analytical Approach, DTE Electric comments that if the risk evaluation must be measured in net present value of revenue requirements (NPVRR), it will limit the type of risk analysis methodology that a utility may select. The company contends that not all of the "methodologies listed in the Risk Assessment section will have results stated in terms of a revenue requirement." DTE Electric's initial comments, p. 1.

ABATE responds that although a robust risk analysis is beneficial, some risk evaluations many not produce a result in terms of an NPVRR. Therefore, ABATE supports DTE Electric's recommendation "so long as (1) annual revenue requirements, (2) present value of annual revenue requirements, and (3) net present value of revenue requirements are developed and reported for each scenario and sensitivity, the method by which risk is analyzed and reported need not be in net present value of revenue requirements." ABATE's reply comments, p. 2.

The Commission prefers that utilities retain flexibility in selecting the type of risk analysis methodology performed and therefore adopts DTE Electric's recommendation, albeit with the stipulations suggested by ABATE. The Commission amends section XV) Modeling Results accordingly:

> An analysis of the capital costs, energy production, energy production costs, fuel costs, energy served, capacity factor, emissions (levels and costs), and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state. The following suggest several elements that address the specific items to be included. They are not necessarily exhaustive.
>
> a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination);
> b) Scenario and sensitivity results, including **annual revenue requirements, present value of annual revenue requirements and net present value of** revenue requirements ~~and financial impacts (NPV)~~, **and** portfolio capacity including additions and retirements. Include monthly and annual energy pricing, and resource capacity and load factors;
> c) Business as usual/reference case portfolios options to be selected from;
> d) Analysis of IRP results;
> e) Risk assessment of each scenario.

4. Demand-Side Resources

ABATE requests that the Commission amend the IRP filing requirements to facilitate an on-going dialogue between utilities and customers interested in participating in DR programs. ABATE recommends that, whenever feasible, the Commission should require the utilities to augment their projections with customer feedback. ABATE contends, however, that it is not suggesting that utilities invest resources or survey every class of customer; rather, utilities should be required "to contact their accounts with an average demand of 1 MW or greater to gauge their appetite for demand response." ABATE's initial comments, p. 2.

Advanced Energy Management Alliance (AEMA) maintains that, pursuant to the IRP filing requirements, utilities are only required to file summary information about existing DR programs and potential expansion plans, which denies the utilities the opportunity to make holistic and informed decisions. AEMA recommends that utilities should "include new and existing DR resources in their resource screen and portfolio modeling process, as well as in their ultimate preferred course of action if DR is found to maximize the portfolio's objectives." AEMA's initial comments, p. 2.

AEMA argues that for utilities to broadly pursue and consider DR resources in their IRP, the utilities must make DR capacity available to alternative electric suppliers (AESs). According to AEMA, if the AESs do not already offer DR to retail open access (ROA) customers, the utilities risk being locked out of the market. AEMA's initial comments, pp. 2-3.

In addition, AEMA comments that utilities could pursue DR through bilateral programs with third-party aggregators or by developing a model tariff for DR that allows customers to voluntarily enroll in the program, either directly or through an aggregator. AEMA notes that Indiana Michigan Power Company has a similar tariff.

DTE Electric comments that the requirement to provide data on the previous five years' load management programs is burdensome and not relevant to an IRP, but rather more appropriate for a reconciliation case.

Both DTE Electric and Consumers responded to ABATE's suggestion that the utilities be required to contact accounts with an average demand of 1 MW or greater. DTE Electric argues that IRP proceedings are not the appropriate forum to comment on the DR process or customer interest in DR programs. The company notes that it is addressing customer interest in DR programs in Case No. U-18255 and the Statewide DR Potential Study. Consumers avers that it "discussed the DR Program with 66% of its eligible large customers. The Company has successfully enrolled 17% of those customers in its DR Program resulting in a fully subscribed (50.1 MW) 2017 DR Program and (60 MW) 2018 DR Program." Consumers' reply comments, p. 2. According to Consumers, some large customers chose not to participate because they did not have enough non-essential load to curtail or the customers' high demand was outside of the program hours.

In response to AEMA's recommendation for third-party aggregation for DR programs, Consumers notes that it has already provided numerous comments opposing third-party aggregation and requests that the Commission refer to its reply comments in Case No. U-18418.

Acknowledging DTE Electric's claim that it may be too burdensome to provide the previous five-years' load management programs, ABATE requests that the Commission should, at a minimum, require the utilities to provide the historical data by class and program on an annual energy and peak reduction basis. ABATE asserts that utilities will have already "developed the hourly (or typical week) load shapes for the programs going forward to use as inputs for its IRP, so no additional work would be required." ABATE's reply comments, p. 2.

In response to ABATE's request that the Commission ensure that there is an on-going dialogue between utilities and their customers regarding DR programs, the Commission finds that this is a process more appropriately managed by the utilities and their customers. In addition, the Commission's recently completed DR potential study specifically targeted large customers to gauge their interest in DR and the preferred program design features. *See,* September 15, 2017 order in Case No. U-18369 (September 15 order).

Regarding AEMA's suggestion that utilities should include new DR resources in their IRP, the Commission notes that the IRP filing requirements do not preclude the utilities from including new DR resources in their resource screen and portfolio modeling process and do not prevent the utilities from providing their ultimate preferred course of action if DR is found to maximize the portfolio's objectives.

The Commission agrees with AEMA that the utilities should expansively pursue and consider DR in their IRPs. However, the Commission does not agree that the DR potential associated with AES customers will be locked out of the market if the customer's current AES is not actively pursuing DR with its customers, because aggregation of AES customer DR is not currently prohibited in Michigan. *See,* September 15 order and November 21, 2017 order in Case No. U-18197, pp. 12-14.

ABATE agrees with DTE Electric that it is irrelevant and too burdensome to provide data on the previous five years' load management programs, but requests that the Commission require historical data by class and program on an annual energy and peak reduction basis. The Commission agrees with DTE Electric and removes the requirement. The Commission declines to adopt ABATE's recommendation, noting that this information is available in other cases filed with the Commission.

5. Renewables and Renewable Portfolio Standards Goals

UCS requests that utilities be required to show more than economic justification for a potential reduction in RE. According to UCS, the justification for reducing RE should include a discussion of any increase in emissions, communities most affected by the increase in emissions, and the utility's response to these impacts on public health, the environment, and the economy.

There are no reply comments. Language has been added to section XVIII) Environmental to require significantly more emissions reporting.

The Commission notes that, in April 2017, Governor Rick Snyder created the Environmental Justice Work Group that is developing recommendations to improve environmental justice awareness and engagement in state and local agencies and recommendations for the implementation of environmental justice guidance, training, curriculum, and policy that further increases the quality of life for all Michiganders. Regarding discussions before the Commission addressing communities most affected by the increase in emissions and the utility's response to these impacts on public health, the environment, and the economy, the Commission finds that these issues are more appropriately addressed in a CON proceeding, rather than an IRP proceeding, when the siting for new proposed generating units is known.

6. Transmission Analysis

DTE Electric requests that the following footnote be added to subsections d) and e) of section XII) Transmission Analysis: "Information provided by the transmission owner should be related to proposed projects in an RTO [regional transmission operator] planning process and include a technical feasibility assessment. Any proposed projects should ultimately be approved through an RTO planning process." DTE Electric's initial comments, p. 2. The company believes that this additional information is required to support an informed IRP process. In addition, DTE Electric comments that any transmission project opportunities identified in the IRP will require RTO review, support, and approval.

DTE Electric also recommends removing subsection e) 2) because transmission owners do not facilitate PPAs and any PPAs made outside of the Midcontinent Independent System Operator, Inc., zone would require a specific point-to-point transmission study. The company is concerned that because there are a vast number of possible scenarios, the expansive language in this subsection may be interpreted as a mandate to study all options. *Id.*

As an initial matter, International Transmission Company d/b/a ITC*Transmission* and Michigan Electric Transmission Company, LLC (ITC) notes that the IRP and RTO planning processes are independent of each other, driven by different considerations, and operate on different calendar cycles. According to ITC, the utility may provide information during the IRP process that was previously unknown to the transmission owner, and it may affect the transmission owner's assessment of the transmission system's requirements. Because the transmission owner "is in the best position to determine the relevance and effects on the transmission system of the . . . IRP," ITC argues that it is not logical to limit the information provided by the transmission owner to projects proposed in the RTO planning process. ITC's initial comments, p. 2. ITC contends that DTE Electric's proposed footnote contains arbitrary limitations and that, therefore, it should be rejected.

Although ITC admits that transmission owners are not parties to PPAs, it maintains that the transmission system is utilized by parties to PPAs. As a result, ITC argues, PPAs impact the transmission system, and the transmission owners are in a unique position to analyze and address these issues. ITC explains that, for example, the transmission owner may conduct a feasibility analysis to ensure that the system can support the desired import; if the necessary infrastructure does not exist, the transmission owner may modify the transmission system to support the PPA. ITC concludes, "Therefore, the transmission owner may have information about the transmission system related to power purchase agreements that should be shared with the utility through the IRP process, and subsection (e)(2) of Section (XII) should not be deleted from the Integrated Resource Plan Filing Requirements." *Id.*

The Commission agrees with ITC and rejects DTE Electric's proposed footnote. Sections 6t(h) and (j) require that, in its IRP, the utility shall include an "analysis of potential new or upgraded electric transmission options for the electric utility" and "[p]lans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements." As asserted by ITC, due to its position, the transmission owner has the unique ability to determine whether and how the IRP will potentially affect the transmission system. Therefore, a thorough transmission analysis would not be possible if the analysis was limited to projects proposed in the RTO planning process. For the same reason, the Commission believes that it is appropriate to retain the portion of subsection e) that requires transmission owners to consider PPAs as potential transmission options that could impact the utility's IRP.

7. Modeling Results

DTE Electric comments that the last requirement of section XV) Modeling Analysis includes a risk assessment of each scenario that is overly detailed in scope and fails to add value. The company opines that the "risk analysis should be all encompassing, capturing the appropriate level of risk." DTE Electric's initial comments, p. 2.

In response, ABATE argues that the scenarios reflect future forecasts of the world and, therefore, each scenario should require a risk assessment. ABATE states that a sensitivity analysis is one of the recognized methods to assess risk, and sensitivities are required, thus running sensitivities should be an unavoidable conclusion.

The Commission disagrees with DTE Electric that a risk assessment for each scenario is excessive and valueless; rather, a scenario is not useful if not accompanied by a sensitivity analysis. The Commission also determines that it is not overly burdensome for a utility to perform one sensitivity for each scenario.

8. Proposed Course of Action

On page 2 of its initial comments, DTE Electric comments that, in section XVI) Proposed Course of Action, the "revenue requirement comparison and Rate Impact/Financial Information section under the Proposed Course of Action is redundant. The data will be captured under the Modeling Results section." The Commission agrees and removes these sections.

9. Rate Impact and Financial Information

Consumers comments that subsections g) emissions cost and h) effluent additive costs of section XVII) Rate Impact and Financial Information are already embedded in subsections a) through e) and, therefore, additional breakout of these costs is unnecessary. In addition, Consumers states that "the proposed IRP Filing Requirements include a requirement to provide an exhibit and/or workpaper presenting an environmental compliance strategy demonstrating how the utility will comply with all applicable federal and state environmental regulations, laws, and rules, including cost analysis of compliance on existing generation fleet going forward." Consumers' initial comments, p. 2. In the company's opinion, this exhibit and/or workpaper addresses the information sought through the emissions and effluent additive costs subsections.

Regarding subsection i) non-reoccurring expedited capital expenditures, Consumers asserts that the intent is unclear, and it is ambiguous what should be included. The company argues that the costs associated with a new build of a generating resource to fill a capacity need earlier than expected could be interpreted as a "non-reoccurring expedited capital expenditure." Consumers' initial comments, p. 2. And, Consumers opines, capital investments related to maintaining existing generators could be considered "non-reoccurring expedited capital expenditures." *Id.*, pp. 2-3. As a result, the company argues that "It is not necessary to evaluate non-reoccurring expedited capital expenditures in isolation because the analysis conducted through the IRP holistically evaluates the cost risks and benefits of a generating portfolio, whether a particular generating resource requires capital expenditures occurring in earlier years or not." *Id.*, p. 3.

ABATE disagrees, maintaining that utilities should be required to break out emissions costs from effluent additive costs because not all scenarios and sensitivities will contain both. In response to Consumers' comments regarding non-reoccurring expedited capital expenditures, ABATE recommends that the Commission retain this requirement and provide additional clarity, because "separating these costs is critical to accurately assessing the economics associated with existing assets or proposed acquisitions of existing assets." ABATE's reply comments, p. 3.

ABATE asserts that the information provided by the utilities in this section should correspond with the information provided in the Approval of Costs section because it will improve the accuracy of the IRP. ABATE reasons that if a utility is seeking cost recovery through its IRP, there is no logical reason to use anything other than the actual costs for those specific projects; departing from the costs provided in the Approval of Costs section is counterproductive. ABATE's initial comments, p. 2. Additionally, ABATE recommends that the utilities provide both nominal and net present values whenever possible.

In its reply comments, Consumers states that the purpose of section XVII) Rate Impact and Financial Information is to evaluate the reasonableness and prudency of the proposed course of action set forth in the modeling results, not to approve recovery of costs. Therefore, the company recommends that the Commission reject ABATE's proposal.

The Commission finds that subsections g) emissions cost and h) effluent additive costs should be specifically identified for each scenario because without detailed costs, it is difficult, if not impossible, to perform an accurate environmental assessment. As ABATE suggests, the Commission will be examining costs for purposes of cost recovery under this new IRP framework. *See,* MCL 460.6t(11) and (17). However, the Commission agrees with Consumers that subsection i) non-reoccurring expedited capital expenditures should be excluded because it may be characterized as more of an emergency expenditure rather than an expense set forth in a long-term resource plan such as an IRP.

10. Environmental

UCS recommends that a utility's IRP include the estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and for the facility's lifetime. UCS requests that the emissions reporting be required for the utility's proposed plan and the reasonable alternatives that were considered. In UCS's opinion:

> Additional pollutants should also be reported to facilitate a comprehensive review of the potential environmental and public health impacts of a utility's proposed plan and its alternatives, including the additional pollutants of methane, fine particulate matter, lead, volatile organic compounds, heat and other constituents discharged to public waters, and production of ash and other potentially harmful solid-waste materials.

UCS's initial comments, pp. 1-2.

UCS also recommends that the Commission require utilities to provide, at a minimum, a discussion of the equity impacts of the preferred IRP and reasonable alternatives, including identification of communities that will bear a disproportionate share of the environmental and/or public health impacts of the utility's proposed IRP and options for mitigating, remedying, or eliminating these impacts. *Id.*, p. 2.

Consumers replies that "emissions levels and costs" are already included in the "Modeling Results" section of the IRP filing requirements, and, therefore, UCS's recommendation is redundant. Regarding UCS's proposed discussion of equity impacts, Consumers claims that such a discussion is not required by Act 341, and it would be challenging and burdensome for the company to analyze and include an equity discussion in the IRP filing.

The Commission agrees with UCS that additional reporting for emissions should be required to provide a more accurate assessment for the alternative plans. However, the Commission declines to increase reporting requirements for pollutants because the Michigan Department of Environmental Quality manages this type of reporting and it would be duplicative. And, as discussed above, the Commission finds that equity analyses are more appropriately performed in a CON proceeding.

11. Exhibits and Work Papers

ABATE notes that, in Case No. U-18419, it was "forced to file a motion to compel DTE Electric ("DTE") to provide access to the Strategist and PROMOD software, including all of the working models in electronic format." ABATE's initial comments, p. 3. ABATE claims that the purpose of the motion was to gain access to information that was fundamental to DTE Electric's case. According to ABATE, the company objected and argued that ABATE should purchase the software for its own use. The administrative law judge (ALJ) in Case No. U-18419 ruled that DTE Electric must provide ABATE access to the software without ABATE having to purchase it. October 10, 2017 Ruling Granting Joint Motion to Compel Discovery in Case No. U-18419, p. 21.

To avoid a similar dispute in each IRP proceeding, ABATE recommends that the Commission add language to the IRP filing requirements requiring that the utility provide: (1) all input/output data in Excel format; (2) access to the modeling software; (3) modeling files used to generate the outputs; and (4) an index of the options selected within the model. *Id.*, p. 4.

Similarly, Energy Michigan, Inc., comments that section XIX) Exhibits and Work Papers should be amended to include third-party reasonable access to software the utility uses in performing its IRP. According to Energy Michigan, access should be granted to third parties pursuant to a protective order consistent with those issued in Case Nos. U-18419 and U-17429.

Consumers recommends that the Commission reject ABATE's and Energy Michigan's proposal, asserting that the ALJ's ruling in Case No. U-18419 was based on the facts and circumstances specific to that case, Case No. U-18419 is a CON proceeding and not an IRP case, and the proposal improperly generalizes information which may differ between utilities. In addition, Consumers argues that intervenors should not be provided access "to confidential and proprietary modeling information without any mechanisms which would prevent the public disclosure of such information, like a protective order." Consumers' reply comments, p. 3. In the event the Commission requires that the utilities provide access to modeling software, the company requests that the Commission require the intervening parties to negotiate confidentiality agreements with model vendors so that the intervening parties, not the utility, are liable for any improper public disclosure of confidential information caused by the intervening parties.

DTE Electric argues that requiring the company to share its software license with intervenors at no cost is contrary to well-established law. The company maintains that a license is granted by a licensor to a licensee, and DTE Electric, as the licensee, does not have the authority to share the license with intervenors. In addition, DTE Electric asserts that Case No. U-18419 may be distinguished from the present case because, in Case No. U-18419, the intervenors were informed at the outset that specific software was used in the company's IRP filing and the intervenors chose to hire consultants who did not possess the requisite license to access the software used by DTE Electric. According to the company, the intervenors in Case No. U-18419 could have avoided the need to file a motion to compel but chose not to.

DTE Electric proposes that, for future IRP cases, third parties should hire consultants who are trained in and licensed to use the software utilized for the company's IRP. Or, the company recommends that third parties petition the utility consumer representation fund to recover costs to acquire such licenses. DTE Electric's reply comments, p. 2.

The Commission agrees with DTE Electric that a utility should not be required to share its software license or to purchase a license for the use of the intervening parties. The Commission notes that funding for an intervening party's software license may be available from other sources, including the Utility Consumer Representation Fund. However, the Commission finds that utilities must supply to the intervening parties all input assumptions that are not included in the modeling software program and output modeling data in Excel format. To subsection b), the Commission adds the following language: "Modeling inputs and outputs in the model-dependent binary format should be made available to parties that obtain a license."

Filing Requirements and Instructions for Certificate of Necessity Alternative Proposals for Electric Generation Capacity Resources

Filing Announcement

Energy Michigan requests that the Commission amend this section to allow an AES seeking to submit an alternative proposal the opportunity to engage in a public meeting with the Staff and interested parties to provide an overview of the proposed alternative resource. According to

Energy Michigan, this is especially important for an AES that is currently producing at least 200 MW of firm electric generation capacity resources and that is submitting the proposal directly to the Commission pursuant to Section 6s(13) of Act 341. There are no reply comments. The Commission amends the alternative proposals to include an additional section prior to the Filing Announcement section as follows:

> Pre-Filing Consultation
>
> At any time prior to filing an alternative proposal, a supplier may request a pre-filing consultation meeting with the Commission Staff (Staff). The purpose of the pre-filing consultation meeting is to assist the supplier in refining the alternative proposal filing, and to facilitate efficient regulatory review. The Staff recognizes that all projects are not the same and that the information needed for one project will not necessarily be appropriate for the next. For some projects, a complete application may require less information than for others. For this reason, a pre-filing consultation is important and highly encouraged.

Contents of the Alternative Proposal

Energy Michigan recommends that the sentence in subsection c) which requires a "description of significant contract provisions that could result in early termination of the contract" be deleted because it is vague and overreaching. According to Energy Michigan, other controlling statutes do not require a description of utility PPAs, and it creates a disadvantage for independent power producers. There are no reply comments. The Commission disagrees with Energy Michigan and finds that significant provisions in PPAs that could result in early termination are critical to understanding whether the PPA will be expected to reliably supply energy.

Case No. U-18461

Case No. U-18461 was opened for the limited purpose of receiving comments on the IRP filing requirements and alternative proposals. Therefore, this docket shall be closed.

THEREFORE, IT IS ORDERED that:

A. The Application Instructions for Integrated Resource Plan Filings and Filing Requirements and Instructions for Certificate of Necessity Alternative Proposals for Electric Generation Capacity Resources, attached as Exhibits A and B, respectively, are approved as amended.

B. Case No. U-18461 is closed.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so by the filing of a claim of appeal in the Michigan Court of Appeals within 30 days of the issuance of this order, under MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

Sally A. Talberg, Chairman

Norman J. Saari, Commissioner

Rachael A. Eubanks, Commissioner

By its action of December 20, 2017.

Kavita Kale, Executive Secretary

Integrated Resource Plan

Filing Requirements

Pursuant to Public Act 341 of 2016, Section 6t

Application Instructions for Integrated Resource Plan Filings

These application instructions apply to a standard electric utility application for Michigan Public Service Commission (Commission) approval of an Integrated Resource Plan (IRP) under the provisions of MCL 460.6t, as well as an IRP that may be filed under the provisions of MCL 460.6s.[1] The application shall be consistent with these instructions, with each item labeled as set forth below. Any additional information considered relevant by the utility may also be included in the application.

Schedule

A utility shall coordinate with the Commission Staff (Staff) in advance of filing its application to avoid resource challenges with IRP applications being filed at the same time as IRP applications filed by other utilities. A utility may be requested to delay its IRP application to preserve a 21-day spacing between IRP applications.

Following the initial IRP applications, the utilities shall comply with all future filing deadlines directed by the Commission and shall continue to coordinate with the Staff to schedule future IRP application filing dates.

Filing Announcement

To facilitate the scheduling and preparation of IRP proceedings, a utility, who intends to file an IRP on a date other than its scheduled filing date, shall file a filing announcement, in a new docket, at least 30 calendar days prior to the proposed filing. The filing announcement, along with a proof of service, shall be served on all parties granted intervention in the utility's last IRP case and the utility's last electric rate case. If the IRP described in the filing announcement is not filed within 120 days after filing of the announcement, the filing announcement will be considered withdrawn. If a

[1]Variations from the standard instructions may occur as allowed by MCL 460.6t(4) for multistate utilities and those serving fewer than 1 million Michigan customers.

certificate of necessity (CON) is also being filed, the same filing announcement would serve as the filing announcement required for the CON.

The filing announcement shall include:

a) Statement of intent to file an IRP;
b) Estimated date of filing;
c) Information related to any stakeholder engagement meetings that have already taken place or are scheduled to take place; and
d) Information related to any CON application that would be filed with the utility's IRP.

The Commission may, if necessary, order a delay in filing an application to establish a 21-day spacing between filings. The filing announcement shall be submitted at least 30 calendar days prior to the IRP application, thus providing the Commission with sufficient time to issue an order regarding the 21-day spacing if it so chooses.

Pre-Filing Request for Proposals

Each electric utility whose rates are regulated by the Commission shall issue a request for proposals (RFP) to provide any new supply-side capacity resources needed to serve the utility's reasonably projected electric load, applicable planning reserve margin, and local clearing requirement for its customers in this state, as well as customers located in other states but served by the utility, during the initial three-year planning period to be considered in each IRP to be filed, as outlined in MCL 460.6t. The utility shall comply with the following:

a) The utility shall include with the IRP application documentation demonstrating that the RFP process was completed;
b) The utility's RFP process is subject to audit by the Staff;
c) The IRP filing shall include evidence that the pre-filing RFP process was conducted in a manner consistent with the Commission's code of conduct, and applicable state, federal, and Commission rules;

d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, pursuant to MCL 460.6t(6); and

e) The RFP shall allow for proposals to provide new supply-side capacity in the form of a purchase power agreement for a period that is the lesser of the study period or of the useful life of the resource type proposed.

Stakeholder Engagement and Public Outreach Process

Participant engagement early in the development of the IRP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decision-making process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.

In the 12 months prior to the IRP filing, each utility is encouraged to host update workshops with interested participants. The purpose of the pre-filing workshop(s) is to ensure that participants have the opportunity to provide input and stay informed regarding: (1) the assumptions, scenarios, and sensitivities; (2) the progress of the utility's IRP process; and (3) plans for the implementation of the proposed IRP. Documentation demonstrating the public outreach process undertaken by the utility shall be included with the IRP filing. Documentation may include:

a) Workshop dates and times, including times outside of the workday;
b) Evidence that notice of the workshops was provided to the public;
c) Meeting minutes;
d) Meeting or workshop attendance lists;
e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application; and

f) Discussion indicating if or how the public outreach process influenced the IRP.

A minimum of two stakeholder engagement workshops are recommended. A stakeholder engagement workshop will provide stakeholders with an opportunity to provide input regarding the utility's assumptions, inputs, and modeling methodologies employed during the development of the IRP. The utility is encouraged to invite stakeholders, including expected intervenors and the Staff, to its stakeholder engagement workshops.

If the stakeholder engagement workshops are not open to the public, two additional public meetings are recommended. The public meetings are intended to educate the public on the utility's planning process as well as provide an opportunity for the public to comment. The public meetings should be offered in the utility's service territory in geographic locations convenient to customers, with advanced notice provided to customers in the utility's service territory. The utility is encouraged to consider holding public meetings after normal business hours to encourage attendance.

If the utility chooses to hold pre-filing workshops, including stakeholder engagement workshops or public meetings, the utility shall prepare a public outreach report to document the outcomes of any pre-filing workshops, and shall file the report with the IRP application.

Risk Assessment Methodology

The utility's IRP filing shall include a thorough risk analysis of the preferred plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the preferred plan and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies for each scenario to determine how each strategy would perform in an unexpected range of possible futures. The IRP shall include a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent-based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.

Confidential Information

Transparency and the use of data that can be shared with the Commission, the Staff, and intervenors is encouraged. Proprietary, confidential, and other nonpublic materials used in the development of the forecasts, scenarios, or other aspects of the IRP shall be presented in such a way that the proprietary and confidential nature of the materials is preserved. The use of publicly available data and materials is encouraged in lieu of proprietary and confidential materials, and claims that information is proprietary or confidential should be justified by the utility.

Inclusion of specific materials in the IRP filing may be contingent upon appropriate confidentiality agreements and protective orders. Proprietary, confidential, and other nonpublic materials filed as part of the IRP shall be clearly designated by the utility as confidential.

Approval of Costs

For the Commission to specify the costs to be approved for the construction of or significant investment in supply or demand-side facilities, or contractual agreements, excluding short-term market capacity purchases to meet state reliability mechanism capacity requirements, in accordance with MCL 460.6t(11) through (12), the following information, data, and documents shall be provided:

I) For specific supply-side resources (inclusive of storage technologies such as battery storage) of less than 225 megawatt (MW) (this threshold shall be applied to the nameplate capacity of a project, not individual generators, storage facilities, etc.), that are planned to go into service within three years following the approval of the IRP, the following evidence (covering the lifespan of the project) shall be provided:

a) A description of the plant size, type, and summary of engineering/design specifications. The description shall also include the following:
    i. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
    ii. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and
    iii. Annual depreciation on the capital investment;
b) Projected annual return and income taxes on capital investment;
c) The operation and maintenance (O&M) costs over the life of the facility described as costs which are variable, in current dollars per kilowatt-hour (kWh), with expenses for fuel and non-fuel items indicated separately; and costs which are fixed, in current dollars per kilowatt;
d) Projected property taxes;
e) The rates of escalation of cost, including:
    i. Capital costs;
    ii. O&M costs which are variable and related to fuel;
    iii. O&M costs which are variable and unrelated to fuel; and
    iv. O&M costs which are fixed;
f) The total annual average cost per kWh at projected loads in current dollars for each year of the plan for the proposed facility;
g) Equivalent availability factors, including both scheduled and forced outage rates;
h) Capacity factors for each year in the planning period;
i) Operation cycle (i.e., baseload, intermediate, or peaking), identifying expected hours per year of operation, number of starts per year, and

cycling conditions for each year in the planning period;

j) Heat rates (efficiency) for various levels of operation;

k) Unit lifetime, both for accounting book purposes and engineering design purposes, with explanations of differences;

l) Lead time, separately identifying the estimated time required for engineering, permitting and licensing, design, construction and pre-commercial operation date testing;

m) Potential socioeconomic impacts, such as employment, for the local region of the proposed supply-side resource, construction of or significant investment in an electric generation facility, or the purchase of an existing electric generation facility.

II) Renewable Resources: The utility shall file data consistent with its renewable energy plan. (For incremental renewable energy beyond the 15% requirement in 2021 and any renewable energy to be constructed or purchased after the conclusion of the 20-year renewable planning period ending in 2029, the utility shall file as set forth below.) Revenue requirement and incremental costs of compliance shall be calculated to include the following:

a) Capital, operating and maintenance costs for renewable energy systems (including property taxes and insurance for renewable energy systems);

b) Financing costs;

c) Costs that are not otherwise recoverable in base rates including interconnection and substation costs;

d) Ancillary service costs;

e) Cost of purchased renewable energy credits (RECs) other than those purchased for non-compliance;

f) Cost of contracts;

g) Expenses incurred as a result of governmental action including changes in tax or other laws;

h) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029;

i) Recovery to include the authorized rate of return on equity, which will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved (only through 2029); and

j) Provide the following information in relation to renewable resource cost recovery:
   i. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and
   ii. Forecast through the end of the renewable plan period of the regulatory liability balance.

III) Demand Response and Energy Waste Reduction: The utility shall provide the following information in relation to demand response programs, energy waste reduction programs, and distributed generation programs cost approval and recovery. For each individual program or group of programs, provide:

a) Total annual cost including:
   i. Annual O&M cost for each individual portfolio of energy waste reduction, demand response, and distributed generation programs;
   ii. Annual capital cost for each individual portfolio of energy waste reduction, demand response, and distributed generation programs; and
   iii. Expected cost-sharing or financial incentive granted to the utility by the Commission;

b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable;

c) Maximum single event demand reduction;

d) Total resource capacity (MW) and type (load modifying resource, emergency demand response, etc.) reported to the applicable regional transmission organization (RTO)/independent system operator (ISO);

e) Total energy reduction achieved (megawatt-hours (MWh)); and
f) Description of program, including customer enrollment, technology used, and marketing plan.

Waivers and Process for Smaller and Multistate Utilities

An electric utility with fewer than 1,000,000 customers in this state may request a waiver to any portion of these IRP filing requirements. Any request for a waiver shall include a discussion and justification outlining why the waiver is warranted and in the best interest of its customers. Discussion and justification for the requested waiver shall include a description of the utility's current and forecasted energy and capacity needs, and its plan for meeting those needs over the upcoming ten years.

If the utility requires resolution of a waiver request prior to filing an IRP application, the utility shall file the waiver request no less than 60 days prior to the filing of the IRP application.

An electric utility with fewer than 1,000,000 customers in this state may request approval from the Commission to file an IRP jointly with other smaller utilities. Commission approval is required prior to filing a joint IRP.

A non-multistate Michigan electric utility serving fewer than 1,000,000 customers may elect to file an IRP, based on its specific circumstances, that deviates from these requirements, but that is subject to the Staff's ability to request supplemental information. The filing shall include an explanation of why the deviations are reasonable under its circumstances. The Commission shall review any such filings under the traditional "just and reasonable" standard.

Northern States Power Company-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other jurisdictions. Due to the provisions in MCL 460.6t(4) regarding multistate IRPs, Northern States Power Company-Wisconsin and Indiana Michigan Power Company may utilize the IRP filing requirements of another state in accordance with those provisions. However, the Commission reserves the right to request additional information to facilitate its review of the IRP as it relates to Michigan.

IRP Report and Documentation

The utility's IRP filing shall demonstrate compliance with MCL 460.6t and include the following items:

a) Letter of transmittal expressing commitment to the approved preferred resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisition strategy, acknowledging that the utility reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances;
b) Technical volume(s) that fully describe and document the utility's analysis and decisions in selecting its preferred resource plan and resource acquisition strategy;
c) The data and information requested in the Commission's IRP filing requirements included herein; and
d) Any other information deemed relevant by the utility.

The utility's IRP filing shall include an IRP document(s) that fully describes and documents the utility's analysis and decisions in selecting its preferred resource plan and resource acquisition strategy. To facilitate a similar format for each utility's application, the utility is encouraged to align its report with this provided outline and include at least the following items:

I) Executive Summary:

An IRP shall include an executive summary, suitable for distribution to the public. The executive summary shall be an informative non-technical description of the preferred resource plan and resource acquisition strategy. The executive summary shall summarize the contents of the IRP document and shall include the following:

a) An overview of the planning period examined in the IRP analysis and application; and
b) A brief introduction describing the utility, its existing facilities, existing purchase power arrangements, existing demand-side programs, existing demand-side rates, and the goal to be achieved by its proposed course of action and implementation strategy.

II) Table of Contents: Shall be provided.

III) Table of Figures: Shall be provided.

IV) Introduction:

The utility shall describe resource plans to satisfy at least the objectives and priorities identified in MCL 460.6t. The utility may identify and/or describe additional planning objectives that the resource plan will be designed to meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that consider the planning objectives and priorities. The introduction shall include the following:

a) General description of the utility's existing energy system, including:
    i. Net present value of utility revenue requirements,[2] with and without any financial performance incentives for demand-side resources;
    ii. Revenue requirement of existing generation and power

[2] The assumed discount rate shall be included along with a justification for the assumed discount rate. Results should be presented in nominal dollars.

purchase agreements;

iii. Summary of existing generation and power purchase agreements by fuel type;

iv. Utility's existing capacity resource mix;

v. Utility's service territory and breakdown of customer class composition; and

vi. Description of planning period analyzed;

b) Statement of power need;

c) Identify and explain the basis for the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements, for each year of the analysis used in each scenario and sensitivity evaluated by the utility as part of the IRP process;

d) Market and regulatory environment influencing resource planning decisions:

i. RTO market and state regulation structure if a multistate utility;

ii. Potential changes to RTO capacity market;

iii. Electric customer choice;

iv. Transmission expansion;

v. Environmental;

vi. Renewable portfolio standards; and

vii. Other;

e) IRP planning process; and

f) Stakeholder report.

V) Analytical Approach:

a) Describe the modeling process, including the duration of the study;

b) Describe and provide a justification for the risk analysis approach adopted from the Risk Assessment Methodology section:

i. The utility shall describe and document its quantification of the risk that affects the evaluation of the various preferred resource plan options;

ii. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings affected its decision on a resource plan;

c) The utility shall describe and document the identification of risk variables and/or combinations of risk variables selected, their ranges, probabilities, ranking, and/or weighting that defines the risk quantification which the various preferred resource plan options were judged; describe how these risk variables were judged to be appropriate and explain how these were determined; and describe the modeling tools and data sources employed during the capacity expansion, and other modeling processes.

VI) Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities;
b) In addition to the utility's own scenarios and assumptions, the inclusion of the established modeling scenarios and assumptions in the MIRPP approved by the Commission in Case No. U-18418, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.

VII) Existing Supply-Side (Generation) Resources:

Detailed account of projected energy and capacity purchased or produced by the utility's owned and contracted resources, including cogeneration resources. Include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:

a) Overview;
b) Fossil-fueled generating units;
c) Nuclear generating units;
d) Hydroelectric generating units;

e) Renewable generating units;
f) Energy storage facilities;
g) Power purchase agreements: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource;
h) RTO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating costs, etc.);
i) Spot market purchases and off-system sales.

VIII) Demand-Side Resources:

Historical and projected load management and demand response programs for the utility in terms of MW and Midcontinent Independent System Operator, Inc., Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and demand response events for each program. The following items are to be included:
    i. Description of current demand response and load management programs for the IRP study horizon, including the amount of load reductions and the expected hours of interruption per day, month, and year for each program;
    ii. Describe the utility's method for determining whether to purchase energy rather than relying on demand response;
    iii. A description of any other programs the utility is considering that could potentially expand demand response resources, including expected load reductions and operating parameters.

IX) Renewables and Renewable Portfolio Standards Goals:

Projected energy purchased or produced by the utility from a renewable energy resource.

a) Describe how the electric provider will meet existing renewable energy standards. If the level of renewable energy purchased or produced is projected to drop over the planning periods, the utility must demonstrate why the reduction is in the best interest of ratepayers;

b) Specify whether the number of MWh of electricity used in the calculation of the renewable energy credit portfolio will be the previous 12-month period of weather-normalized retail sales or based on the average number of MWh of electricity sold by the electric provider annually during the previous three years to retail customers in this state;
c) Include the expected incremental cost of compliance with existing renewable energy standards for the required compliance period;
d) A description of how the electric provider's plan is consistent with the renewable energy goals required by the Michigan Legislature (e.g. 35% combined renewable energy and energy waste reduction goal by 2025);
e) Describe the options for customer-initiated renewable energy that will be offered by the electric provider and forecast sales of customer-initiated renewable energy;
f) Describe how the electric provider will meet the demand for customer-initiated renewable energy.

The following non-exhaustive list suggests several elements that may be included:

a) Sales forecast through 2021 for compliance with the renewable energy standard, through 2025 toward meeting the 35% goal, and through the study period;
b) Detailed resource plan:
    i. Describe the utility's planned renewable energy credit portfolio;
    ii. Forecast RECs obtained via Michigan incentive RECs;
    iii. Forecast expected compliance levels by year to meet the renewable portfolio targets;

iv. Identify key assumptions used in developing these forecasts and the proposed resource portfolio;
v. Identify risks which may drive performance to vary.

X) Peak Demand and Energy Forecasts:

A long-term forecast of the utility's sales and peak demand under various reasonable scenarios. Include details regarding the utility's plan to eliminate energy waste, including the total amount of energy waste reduction expected to be achieved annually, and the cost of the plan:

a) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction;
b) Subsections:
    i. Key variables used to develop forecast;
    ii. Long-term forecasting methodology;
    iii. Forecasting uncertainty and risks;
    iv. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers);
    v. Business as usual deliveries and demand forecast;
    vi. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. U-18418, or subsequent Commission orders relating to IRP modeling parameters and requirements.

XI) Capacity and Reliability Requirements:

The utility shall indicate how it complies, and will comply, with all applicable state, federal, ISO, RTO capacity and reliability regulations, laws, rules and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including the projected costs/revenues of complying with those regulations, laws, and rules. The utility shall include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio.

XII) Transmission Analysis:

In accordance with MCL 460.6t(5)(h), the utility shall include an analysis of potential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:

a) The utility shall assess the need to construct new, or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options;
b) A detailed description of the utility's efforts to engage local transmission owners in the utility's IRP process in an effort to inform the IRP process and assumptions, including a summary of meetings that have taken place;
c) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns;
d) Any information provided by the transmission owner(s) indicating the anticipated effects of fleet changes proposed in the IRP on the transmission system, including both generation retirements and new generation, subject to confidentiality provisions;
e) Any information provided by the transmission owner(s), including cost and timing, indicating potential transmission options that could impact the utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboring RTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery

and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources.

XIII) Fuel

The utility shall include the following:

a) Overview;
b) Natural gas price forecasts under the various scenarios;
c) Oil price forecasts under the various scenarios;
d) Coal price forecasts under the various scenarios;
e) Delivered natural gas prices to existing and new utility-owned generating plants;
f) Delivered oil prices to existing and new utility-owned generating plants;
g) Delivered coal prices to existing and new utility-owned generating plants;
h) Projected annual fuel costs under the various scenarios; and
i) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new and existing generation facility.

XIV) Resource Screen:

Describe the utility's options of resources, including combinations of resources, to serve future electric load such as utilizing existing and planned generation resources, build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a power purchase agreement. The following sections shall discuss each option in detail and options shall be considered in combination to serve future electric load. As described below, workpapers with information on the costs of each resource option and combination of resource options shall be provided with the utility's filing:

a) Existing and planned generation;
b) New build:
    i. New generation technology and operating assumptions;
    ii. New generation development costs;
    iii. New energy integration of storage technology and operating assumptions;
    iv. New energy storage development costs;
c) Distributed generation:
    i. Solar photovoltaic (including solar plus storage);
    ii. Biogas;
    iii. Energy storage;
    iv. Other distributed generation;
d) Market capacity purchases:
    i. Regional market supply outlook;
    ii. Availability of market capacity;
    iii. Market capacity price assumptions;
e) Long-term power purchase agreements;
f) Transmission resources:
    i. Overview;
    ii. Existing import and export capability;
    iii. Transmission network upgrade assumptions for the IRP; and
    iv. Import and export impact on resource strategy.

XV) Modeling Results:

An analysis of the capital costs, energy production, energy production costs, fuel costs, energy served, capacity factor, emissions (levels and costs), and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state. The following suggest specific items to be included. They are not necessarily exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination);

b) Scenario and sensitivity results, including annual revenue requirements, present value of annual revenue requirements and net present value of revenue requirements, and portfolio capacity including additions and retirements. Include monthly and annual energy pricing, and resource capacity and load factors;
c) Business as usual/reference case portfolios options to be selected from;
d) Analysis of IRP results; and
e) Risk assessment of each scenario.

XVI) Proposed Course of Action:

Include a detailed description of:

a) The type of generation technology proposed for a generation facility contained in the plan and the proposed capacity of the generation facility, including projected fuel costs under various reasonable scenarios;
b) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements;
c) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new generation facility; and
d) How the utility will meet local, state, and federal laws, rules, and regulations under the proposed course of action.

The utility shall describe the process used to select the preferred resource plan, including the planning principles used by the utility to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall describe how its preferred resource plan satisfies the following:

a) Strike an appropriate balance between the various planning objectives specified;
b) Utilize renewable and demand-side resources to comply with existing laws and goals and, in the judgment of the utility, are consistent with the public interest and achieve state energy policies; and
c) In the judgment of the utility, the preferred plan, in conjunction with the deployment of demand response measures, has sufficient resources to serve load forecasted for the implementation period.

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the preferred resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain:

a) A schedule to report the status of an approved plan in accordance with MCL 460.6t(14);
b) A schedule and description of actions to implement ongoing and planned demand-side programs and demand-side rates;
c) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction;
d) A net present value revenue requirement comparison of its proposal and reasonable alternatives over the planning period utilized in the analysis. It shall also include the calculation and comparison of the net present value revenue requirement of the utility's proposed plan and alternative resource plans including the alternative resource plans resulting from the Commission-approved modeling scenarios. In addition, the utility shall provide support for its chosen discount rate and discuss how the results of its analysis would change with different discount rate assumptions.

XVII) Rate Impact and Financial Information:

Projected year-on-year impact of the proposed course of action (and other feasible options) for the periods covered by the plan, covering the following accounts:

a) Revenue requirement;
b) Rate base;
c) Plant-in-service capital accounts;
d) Non-fuel, fixed operations and maintenance accounts;
e) Non-fuel, variable operations and maintenance accounts;
f) Fuel accounts;
g) Emissions cost;
h) Effluent additive costs; and
i) Projected change in generation plant-in-service.

The utility shall describe the financial assumptions and models used in the plan. The plan shall include, at a minimum, the following financial information, together with supporting documentation and justification:

a) The general rate of inflation;
b) The allowance for funds used during construction rates used in the plan;
c) The cost of capital rates used in the plan (debt, equity, and weighted) and the assumed capital structure;
d) The discount rates used in the calculations to determine present worth;
e) The tax rates used in the plan;
f) Net present value of revenue requirements for the plan;
g) Nominal revenue requirements by year; and
h) Average system rates per kWh by year.

XVIII) Environmental:

Describe how the utility's proposed IRP will comply with all applicable local, state, and federal environmental regulations, laws, and rules:

a) Include a list of all environmental regulations that are applicable to the utility fleet. Identify which regulations apply to which resources;
b) Include all capital costs for compliance with new and reasonably expected environmental regulations for existing fleet assets in the utility IRP;
c) Provide an annual projection of the following emissions for the study period differentiating between existing and new resources within the proposed IRP:
    i. Tons of sulfur oxides;
    ii. Tons of oxides of nitrogen;
    iii. Tons of carbon dioxide;
    iv. Tons of particulate matter; and
    v. Pounds of mercury.
d) Provide the total projected emissions of the items listed below through the study period for the utility's proposed plan, as well as the scenarios identified in the MIRPP as approved in Case No. U-18418, or modified by Commission order:
    i. Tons of sulfur oxides;
    ii. Tons of oxides of nitrogen;
    iii. Tons of carbon dioxide;
    iv. Tons of particulate matter; and
    v. Pounds of mercury.

XIX) Exhibits and Workpapers:

The filing shall include exhibits and workpapers as outlined below, subject to any license or other confidentiality restrictions that are unable to be resolved by issuance of a protective order.

a) Any workpapers used in developing the application, supporting testimony, and IRP. Such workpapers shall, when possible, be provided in electronic format with formulas intact;
b) Any modeling input and output files used in developing the application,

supporting testimony, and IRP. Such modeling input and output files shall, when possible, be provided in electronic format with formulas intact. The utility shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program. Modeling inputs and outputs in the model-dependent binary format should be made available to parties that obtain a license;

c) Cost data and estimates that were used in the resource screening process to evaluate each electric resource that was considered either individually or in combination with other resources, including renewable alternatives, such as solar, wind, or solar plus battery storage;

d) A description, including estimated costs of each alternative proposal received by the utility;

e) A discussion of any differences between its short-term fuel price forecasts and capacity price curve in the IRP filing, and the short-term fuel price forecasts and capacity price curve in its last power supply cost recovery proceeding;

f) Identification and justification of the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements used in the IRP. The utility shall identify its base case forecasts and a range of sensitivities for each such factor, and explain how those sensitivities were identified. If the base case forecast(s) differs from recent previous forecasts submitted by the utility to the Commission in other cases, the utility shall provide an explanation for such differences;

g) Present an environmental compliance strategy which demonstrates how the utility will comply with all applicable federal and state environmental regulations, laws and rules. Included with this information, the utility shall analyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utilities generation fleet;

h) Estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and over the life of the facilities included in their IRP;

i) A comparison of total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the business as usual case;

j) The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates;

k) An analysis that contains an individualized cost estimate for electric resources that were considered, including renewable alternatives, such as solar, wind, or solar plus battery storage, and such cost estimates for all alternative proposals, solicited or unsolicited, received by the utility;

l) Electricity market forecasts utilized; and

m) Other documents and data underlying the IRP analysis.

Certificate of Necessity
and
Integrated Resource Plan
Alternative Filing Requirements

Pursuant to Public Act 341 of 2016

Section 6s and 6t

Application Instructions for Alternative Proposals

These filing instructions apply to any supplier of electric generation capacity seeking to provide electric generation capacity resources to a utility submitting an integrated resource plan (IRP) under MCL 460.6t or a certificate of necessity (CON) application under the provisions of MCL 460.6s. The proposal shall be consistent with these instructions, MCL 460.6s(13), and MCL 460.6t(6), with each item labeled as set forth below. Any additional information considered relevant by the applicant may also be included in the application.

Pre-Filing Consultation

At any time prior to filing an alternative proposal, a supplier may request a pre-filing consultation meeting with the Commission Staff (Staff). The purpose of the pre-filing consultation meeting is to assist the supplier in refining the alternative proposal filing and to facilitate efficient regulatory review. The Staff recognizes that all projects are not the same and that the information needed for one project will not necessarily be appropriate for the next. For some projects, a complete application may require less information than for others. For this reason, a pre-filing consultation is important and highly encouraged.

Filing Announcement

Notice that a supplier of electric generation capacity intends to file an alternative proposal shall be filed at least 30 days prior to filing a detailed alternative proposal that meets the requirements of this document. The 30-day notice shall be filed in the docket in which the utility filed the initial application. The notice shall include a description of the proposal and proof of service to all parties in the case.

Intervention Status

A supplier of electric generation capacity that intends to file an alternate proposal must request and be granted intervention in the contested case for which the utility has filed its IRP and/or CON application, pursuant to MCL 460.6s(13) and MCL 460.6t(6).

Filing the Alternative Proposal

A supplier of electric generation capacity that intends to file an alternative proposal must file the proposal in the contested case, and the proposal shall be sponsored by a witness for the supplier who will be subject to appropriate discovery and cross examination. All alternative proposals shall be filled within 90 days of the date the application was filed by the utility initiating the contested case for a CON, an IRP, or a contested case containing both a CON and an IRP.

Alternative Proposal Information

All alternative proposals shall contain the following information about the supplier:

a) A description of the developer's/supplier's qualifications including a description of the developer's/supplier's experience in constructing or operating similar facilities;
b) A description of financial standing and credit worthiness;
c) The name, title, and business address of a person to whom correspondence should be directed; and
d) An estimate of capital and operational costs associated with the alternative proposal.

Confidential Information

Proprietary, confidential, and other nonpublic materials filed as part of the application shall be clearly identified and marked accordingly and presented in such a way that the proprietary and confidential nature of the materials is preserved pending the execution of any confidentiality agreements and issuance of protective orders. Availability of specific materials in the application may be contingent upon appropriate confidentiality agreements and protective orders.

Detailed Cost Information

The supplier is not required to disclose detailed cost information provided in response to requests for quotes from potential project contractors any sooner than 120 days after the filing of the utility application and then only after appropriate protective orders and non-disclosure certificates/agreements have been executed.

The supplier filing the alternative proposal may provide a cost update on or before 150 days from the date the utility's application was filed.

Contents of the Alternative Proposal

A utility seeking to construct a new electric generation facility or to make a significant investment in an existing facility, or enter into a power purchase agreement (PPA) shall include the following information:

I) New or Existing Electric Generation Facility (excluding a power purchase agreement):
   a) If applicable, a written description of the proposed or existing site, including identification of the municipality in which the facility will be constructed and the current use of that site;

b) If applicable, the age of the existing facility or facilities to be purchased or modified;
c) Expected generating technology and major systems (including major pollution control systems);
d) Expected nameplate capacity, availability, heat rates, expected life, and other significant operational characteristics;
e) Fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;
f) The expected annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract, and an assessment of whether some or all anticipated emissions and any anticipated health impacts could be eliminated or reduced through the use of feasible and prudent alternatives;
g) Discussion of the rationale behind facility or investment technology, fuel, capacity, and other significant design characteristics;
h) A description of all major state, federal, and local permits required to construct and operate the proposed generation facility or the proposed facility upgrades in compliance with state and federal environmental standards, laws, and rules;
i) If applicable, the status of any transmission interconnection study and identification of any expected or required transmission system modifications;
j) If applicable, natural gas infrastructure required for plant construction and operation not located on the proposed site but required for plant construction and operation;
k) If applicable, a description of modifications to existing road, rail, or waterway transportation facilities not located on the proposed site but required for plant construction and operation;
l) If applicable, water and sewer infrastructure required for

construction and operation not located on the proposed site but required for plant construction and operation;

m) A basic schedule for development and construction, which includes an estimated time between the start of construction, major milestones, and commercial operation of the facility or facility upgrades;
n) An estimate of the proportion of the construction workforce that will be composed of residents of the state of Michigan;
o) For new construction and investment in an existing facility, the proposal shall include the expected typical annual costs associated with operating the facility including fuel, operations and maintenance, and environmental compliance;
p) Describe the effect of the proposed project on wholesale market competition;
q) Any workpapers used in developing the proposal; such workpapers shall, whenever possible, be provided in electronic format with formulas intact;
r) Any modeling input or output files used in developing the proposal; such modeling input and output files shall, whenever possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program; and
s) Any other information that the applicant considers relevant.

II) Purchase of Existing Facility:

a) As applicable, the estimated costs associated with purchasing the existing facility assets including the price to be paid for the assets, acquisition and transition costs, financing costs, and any significant financial liabilities that will accompany the asset transfer; and

b) The expected typical annual costs associated with operating the generation facility including fuel, operations and maintenance, and environmental compliance.

III) Power Purchase Agreement:

a) If applicable, a written description of generation facilities covered by the PPA, the size of each facility, generator technology, expected nameplate capacity, availability, heat rates, expected life, fuel type, other significant operational characteristics and the location of the generation facilities, including identification of the municipalities in which the facilities are located;
b) The name and address of the power provider supplying contract products and services under the PPA;
c) The date the resources covered by the PPA will be available, the proposed term of the PPA, and a description of significant contract provisions that could result in early termination of the contract;
d) The proposed price to be paid for capacity and energy contract products and services delivered under the PPA;
e) If the contract includes provisions which may result in an increase in cost due to the price of fuel, the fuel type and sources, including the identification and justification of fuel price forecasts used over the study period;
f) The annual expected emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, volatile organic compounds, oxides of nitrogen, mercury, and other hazardous air pollutants over the life of the facility or contract and a demonstration that regulated emissions from the facility will comply with applicable federal and state regulations;
g) Any workpapers used in developing the proposal. Such workpapers shall, whenever possible, be provided in electronic format with formulas intact;
h) If available, any modeling input or output files used in developing the proposal. Such modeling input and output files shall, whenever

possible, be provided in electronic format with formulas intact. The applicant shall also identify each modeling program used, and provide information for how interested parties can obtain access to such modeling program; and

i) A copy of the PPA, including an estimate of the capacity and energy payments to be made for contract products and services pursuant to the agreement. The estimated payments shall be presented on a yearly basis in nominal dollars over the primary term of the contract.

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-15896 et al

County of Ingham)

Lisa Felice being duly sworn, deposes and says that on December 20, 2017 A.D. she electronically notified the attached list of this **Commission Order via e-mail transmission**, to the persons as shown on the attached service list (Listserv Distribution List).

Lisa Felice

Lisa Felice

Subscribed and sworn to before me
This 20th day of December 2017

Steven J. Cook

Steven J. Cook
Notary Public, Ingham County, Michigan
As acting in Eaton County
My Commission Expires: April 30, 2018

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Updated 8-18-2017

Attachment C

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to implement the provisions of MCL 460.6s(10) and (11).	))))	Case No. U-15896

At the December 23, 2008 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Orjiakor N. Isiogu, Chairman
Hon. Monica Martinez, Commissioner
Hon. Steven A. Transeth, Commissioner

ORDER AND NOTICE OF OPPORTUNITY TO COMMENT

On October 6, 2008, Governor Jennifer M. Granholm signed into law 2008 PA 286 (Act 286), an amendment to 1939 PA 3. Section 6s of Act 286, MCL 460.6s, provides the option for a utility that seeks to add capacity to its system by construction, renovation, or long-term power purchase to seek one or more certificates of necessity from the Commission. If a utility seeks a certificate of necessity under this section, it must file an application with the Commission, along with an integrated resource plan.

Section 6s(10) provides that within 90 days of the effective date of the amendatory act, the Commission "shall adopt standard application filing forms and instructions for use in all requests for a certificate of necessity under this section." Section 6s(11) provides that the Commission "shall establish standards for an integrated resource plan that shall be filed by an electric utility requesting a certificate of necessity under this section." The subsections to Section 6s(11) describe seven parts that must be included in an integrated resource plan.

In compliance with the statutory requirement to adopt forms, instructions, and guidelines, the Commission hereby adopts the "Public Convenience and Necessity Application Instructions," attached to this order as Exhibit A, and "Integrated Resource Planning Guidelines," attached to this order as Exhibit B.

THEREFORE, IT IS ORDERED that "Public Convenience and Necessity Application Instructions," attached to this order as Exhibit A, and "Integrated Resource Planning Guidelines," attached to this order as Exhibit B, are adopted for purposes of implementing MCL 460.6s(10) and (11).

The Commission reserves jurisdiction and may issue further orders as necessary.

MICHIGAN PUBLIC SERVICE COMMISSION

Orjiakor N. Isiogu, Chairman

Monica Martinez, Commissioner

Steven A. Transeth, Commissioner

By its action of December 23, 2008.

Mary Jo Kunkle, Executive Secretary

Michigan Public Service Commission
2008 PA 286

Filing Requirements and Instructions for Certificate of Public Convenience and Necessity Application Instructions

Application Instructions for Certificate Necessity

These filing instructions apply to an electric utility application for a Certificate of Necessity under the provisions of MCL 460.6s. The application shall be consistent with these instructions, with each item labeled as set out below. Any additional information considered relevant by the applicant may also be included in the application.

Pre-application Consultation Process

Prior to filing the application for a Certificate of Necessity, a pre-application consultation with Commission Staff is necessary. The purpose of the pre-application consultation is to help applicants refine the project application, and to facilitate efficient regulatory review. Applicants should schedule pre-application consultation meetings with Staff well in advance of filing an application with the PSC. Staff recognizes that all projects are not the same and that the information needed for one project will not necessarily be appropriate for the next. For some projects, a complete application may require less information than for other projects. For this reason, pre-application consultation with Staff is important. Early in the consultation process, Staff will identify Staff contacts, clarify the applicability of information requirements for the specific application.

I. Applicant Information

All applications shall contain the following information about the applicant utility.

1. The name and address of the applicant utility seeking the Certificate.
2. A description of the applicant utility, and the name, title and business address of a person to whom correspondence should be directed.

II. Alternate Standards and Criteria for Certain Projects

An electric utility with more than 1 million retail customers in this state seeking a certificate of necessity for a project costing more than $500 million shall follow these instructions. An electric utility with less than 1 million retail customers in this state seeking a certificate of necessity for a project costing less than $500 million may propose different review criteria and approval standards in its application, under MCL 460.6s(2), including modification or waiver of these instructions for good cause shown. The justification for any such proposals shall be addressed in the application. Project cost estimates submitted with the Certificate application do not require final bidding and contracts for project engineering, procurement and construction, and may include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.

III. Confidential Information

Proprietary, confidential, and other nonpublic materials filed as part of the application shall be clearly identified and marked accordingly and presented in such a way that the proprietary and confidential nature of the materials is preserved pending the execution of any confidentiality agreements and issuance of protective orders. Availability of specific materials in the application may be contingent upon appropriate confidentiality agreements and protective orders.

IV. Integrated Resource Plan

An Integrated Resource Plan as required by MCL 460.6s(11) shall be included as an exhibit to the certificate application. The plan shall include the items listed in MCL 460.6s(11) and otherwise comply with the Commission's standards developed under that section.

V. Certificate of Necessity Type

The Certificate of Necessity application shall identify the relief requested. An electric utility may seek one or more of the following Certificates as described in MCL 460.6s (3):

- A Certificate that the power to be supplied as a result of the proposed construction, investment, or purchase is needed.
- A Certificate 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. A proposed action represents the most reasonable and prudent means of meeting the power need if the applicant presents evidence demonstrating that the proposed action is the most cost-effective means of meeting the power need, taking into account the cost of the proposal, the cost of alternatives to the proposal, and the risks associated with the proposal and with alternatives.
- A Certificate that the price specified in the power purchase agreement will be recovered in rates from the electric utility's customers.
- A Certificate that the estimated purchase or capital costs of the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the

new or proposed electric generation facility, will be recoverable in rates from the electric utility's customers.

VI. Certificate of Necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed:

A utility seeking a Certificate of Necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed shall file an application that identifies projected resource requirements, the expected timing of the requirements, along with an Integrated Resource Plan that identifies a proposed course of action.

VII. Certificate of Necessity that the design characteristics of a proposed electric generation facility or investment in an existing electric generation facility or the terms of a power purchase agreement represent the most reasonable and prudent means of meeting future power needs:

An application seeking a Certificate of Necessity to construct a new electric generation facility or to make a significant investment in an existing facility or enter in a power purchase agreement shall include the following information:

A. New or Existing Electric Generation Facility

1. A written description of the proposed or existing site, including identification of the municipality in which the facility will be constructed and the current use of that site.
2. If applicable, the age of the existing facility or facilities to be purchased or modified.

3. Expected Generating Technology and Major Systems (including major pollution control systems).
4. Expected nameplate capacity, availability, heat rates, expected life, and other significant operational characteristics.
5. Fuel Type and Sources, including the identification and justification of fuel forecasts used over the study period.
6. Discussion of rationale behind facility or investment technology, fuel, capacity, and other significant design characteristics.
7. A description of all major State, Federal, and Local permits required to construct and operate the proposed generation facility or the proposed facility upgrades in compliance with State and Federal environmental standards, laws, and rules.
8. If applicable, the status of any transmission interconnection study and identification of any expected or required transmission system modifications.
9. If applicable, natural gas infrastructure required for plant construction and operation not located on the proposed site but required for plant construction and operation.
10. If applicable, a description of modifications to existing road, rail, or water way transportation facilities not located on the proposed site but required for plant construction and operation.
11. If applicable, water and sewer infrastructure required for construction and operation not located on the proposed site but required for plant construction and operation.
12. A basic schedule for development and construction which include an estimated time between the start of construction and commercial operation of the facility or facility upgrades.

13. An estimate of the proportion of the construction workforce that will be composed of residents of the State of Michigan.
14. Descriptions of the supply alternatives to this proposal that were considered, including a “no-build” option, and present the justification for the choice of the proposed project. Comparative costs of supply alternatives shall be included. The supply alternatives shall consider energy optimization and renewable energy
15. Describe the effect of the proposed project on wholesale market competition.
16. Any other information that the applicant considers relevant.

B. Power Purchase Agreement

1. If applicable, a written description of generation facilities covered by the Power Purchase Agreement, the size of each facility, generator technology and fuel type, and the location of the generation facilities including identification of the municipalities in which the facilities are located.
2. The name and address of the power provider supplying contract products and services under the Power Purchase Agreement.
3. For Power Purchase Agreements that are the result of a competitive solicitation, the following shall be included in the Certificate application:

a) A copy of the Request for Proposal (RFP) for Electric Capacity and a description of how the request was issued to potential respondents.

b) Copies of responses to the RFP. Responses submitted as part of a Certificate application may be presented in such a way that the identities of the respondents and other commercially sensitive information is protected.

c) A description of the proposal selection process.

4. The date the resources covered by the Power Purchase Agreement will be available, the term of the Power Purchase Agreement, and a description of significant contract provisions that could result in early termination of the contract.
5. The price to be paid for contract products and services delivered under the Power Purchase Agreement
6. A copy of the proposed Power Purchase Agreement.

VIII. Certificate of Necessity that the estimated capital or purchase costs of the new or existing electric generation facility or the investment in an existing electric generation facility will be recoverable in rates from the electric utility's customers:

An application seeking a Certificate of Necessity to construct a new electric generation facility, to make a significant investment in an existing electric generation facility, or to purchase an existing electric generation facility shall provide an estimate of the costs required for the specified purchase or construction as well as projected facility operation costs. Cost estimates filed with the Certificate application shall include:

A. Construction of new facility or investment in existing facility

1. To the extent applicable and available, engineering, procurement, and construction costs, transmission interconnection costs, owner's costs, and project financing costs shall be included. Estimates filed with the application that are the result of a competitively bid engineering, procurement, and construction contracts shall be separately identified. If the scope, scale, timing, or other aspects of the project including legislative or regulatory uncertainty make competitive bid solicitations unlikely to produce reliable or timely project cost estimates, the application shall include cost estimates developed in an alternative manner, along with a proposed contract strategy for project development and implementation.
2. For new construction, the Certificate application shall include the expected typical annual costs associated with operating the facility including fuel, operations and maintenance, and environmental compliance.
3. For investment and upgrades at an existing facility, the Certificate application shall include an estimate of the incremental operating costs for the facility after upgrades are complete including fuel, operations and maintenance, and environmental compliance.
4. To the extent applicable, the Certificate application shall describe any definitive joint ownership plans for the proposed generation facility assets and the impact such plans will have on the costs for which a Certificate of Necessity is requested. For the purposes of a Certificate application, changes in allocated costs among joint owners shall be considered an aspect of the estimated cost included in the filing.

B. Purchase of Existing Facility

1. As applicable, the estimated costs associated with purchasing the existing facility assets including the price to be paid for the assets, acquisition and transition costs, financing costs, and any significant financial liabilities that will accompany the asset transfer.
2. The expected typical annual costs associated with operating the generation facility including fuel, operations and maintenance, and environmental compliance.

IX. Certificate of Necessity that the price specified in the Power Purchase Agreement will be recovered in rates from the electric utility's customers:

A utility seeking rate recovery for future payments made pursuant to a Power Purchase Agreement shall file a Certificate application providing an estimate of the payments to be made for contract products and services pursuant to the agreement. The estimated payments shall be presented on a yearly basis in nominal dollars over the primary term of the contract.

Michigan Public Service Commission
2008 PA 286

Integrated Resource Planning Filing Guidelines

A. Planning Process and Modeling

An Integrated Resource Plan (IRP) shall cover a planning period of at least ten years. Documentation of the methodologies and materials used in the development of the Integrated Resource Plan shall be filed with the Commission.

The IRP shall include a description of the models, commercial and custom software applications, data providers, and other products that were used as part of the integrated resource planning process. Descriptions shall include the name of the company, governmental department, organization, or entity that developed the software or models, or current owner of the software or model licensing rights. The IRP shall also identify any consultants, contractors, or third parties utilized in the planning process.

B. Forecasts

The IRP shall include a forecast of economic indicators, electric load including customer load and sales by customer class, peak demand, available generation, fuel costs, and environmental costs. Sales and generation forecasts should include, as applicable, the effects of load management, demand response, electric choice participation, energy efficiency measures, net metering service, renewable portfolio standards, environmental limitations, planning reserve margins and system reliability requirements, and other legislative or societal developments that will likely impact future energy requirements.

For each reference forecast and any alternative forecasts the following shall be included:

1. A description of the models, methodologies, and software used to develop the forecast including data requirements, factors affecting model accuracy, and other critical factors affecting resulting forecast.
2. Include critical assumptions affecting the forecast data and methodology, and the sensitivity of the forecast to assumption variability.

C. <u>Supply Resources</u>

Existing Supply Resources:

The IRP filing shall include the following information for utility owned generation, and energy or capacity purchased through power purchase agreements:

1. Forecasted availability and seasonal net generating capacity of each supply resource.
2. Estimated future costs directly incurred that are associated with each supply resource including fuel, operations and maintenance, and environmental compliance.
3. If applicable, proposed or planned changes to existing generating capacity and associated costs, including: those changes and costs associated with the installation and operation of environmental protection facilities, those changes associated with proposed increases in fossil-fuel generation plant efficiencies, and/or any limitations on fossil-fuel generation plant capacities.
4. If applicable, assumptions regarding planning reserve margins and/or provision of ancillary services.

Potential Supply Resources:

The IRP filing shall include a description of the electric power resources considered for future service requirements. The quantity of energy from the supply resources considered during the integrated resource planning process shall not be limited by any minimum requirements set forth by law or commission order. The following information should be included for all potential resources considered in the integrated resource plan:

1. A description of the technologies considered for the new generation source, including the primary fuel and fuel alternatives, capacity, expected availability, and lead time for construction for each technology.
2. The estimated costs of developing potential generating resources including cost components attributable to plant capital costs, engineering, procurement, construction, financing, specific or generalized transmission upgrades, and owner's costs.
3. The estimated costs of operating potential generating resources including fuel, operations and maintenance, and environmental compliance.
4. A discussion of the commercial availability or developmental status of various generation technologies.
5. If applicable, a description of the renewable aspects of any supply side technology and how it will receive credit under any State or Federal Renewable Portfolio Standard requirement.

Transmission:

To the extent practicable, the IRP shall include an analysis of existing transmission import and export capability, proposed transmission projects, and the availability and economic impact of power imports and exports.

D. Demand Reduction Resources

The IRP shall consider Demand Reduction resources such as load management, demand response, energy efficiency, net metering service, and distributed generation as a means of affecting forecasted load requirements. The demand reduction resources considered during the integrated resource planning process shall not be limited to minimum requirements set forth by law or commission order.

Load Management/Demand Response

For load management and demand response programs, the following shall be included:

1. A description of potential and existing load management and demand response programs considered during the resource planning process, including affected customer end-uses and targeted customer classes.
2. Load management and demand response program costs including incentives, equipment, and acquisition costs.
3. Estimated or actual program participation and estimated or actual capacity, energy, and ancillary services savings per program.

Energy Efficiency

For energy efficiency programs, the following shall be included:

1. A description of potential and existing energy efficiency programs considered during the resource planning process, including affected customer end-uses and targeted customer classes.
2. Energy efficiency program costs including incentives, equipment, and acquisition costs.
3. Estimated or actual program participation and estimated or actual capacity, energy, and ancillary services savings per program.

Distributed Generation

The IRP shall provide a description of the existing and potential distributed generation resources considered for future service requirements. The summary of potential resources should include the following information:

1. A description of the distributed generation technology, primary fuel and fuel alternatives, capacity, and expected capacity factor.
2. Costs of developing, acquiring, or purchasing energy from distributed generation resources.
3. A discussion of the commercial viability, availability, or developmental status of distributed generation technologies.
4. If applicable, a description of the renewable aspects of the distributed generation resource and how it will receive credit under any State or Federal Renewable Portfolio Standard requirement.

E. Proprietary and Confidential Information

Proprietary, confidential, and other nonpublic materials used in the development of the forecasts, scenarios, or other aspects of the IRP should be presented in such a way that the proprietary and confidential nature of the materials is preserved. Inclusion of specific materials in the IRP filing may be contingent upon appropriate confidentiality agreements and protective orders. Proprietary, confidential, and other nonpublic materials filed as part of the IRP shall be clearly designated by the applicant as confidential.

F. Legislation and Regulations

The IRP shall present in narrative form a discussion of likely or expected legislative or administrative activity that could result in changes to utility, energy market, or environmental regulatory rules and policies, and of regulatory uncertainty that may impact future operations. The filing shall also identify critical assumptions concerning these matters that underlie the IRP.

G. Scenarios and Risk Analysis

For the purposes of these guidelines, the reference scenario is defined as the set of assumptions and forecasts which are considered to be most probable. Scenario alternatives involve modification to critical assumption parameters defined in the Forecast, Supply Side or Demand Reduction Resource sections of the IRP. Sensitivities involve analysis of the scenarios identified in the IRP under varying forecast sensitivities or combinations of forecast sensitivities as defined in the Forecast section of the plan.

The IRP shall include a discussion of each scenario analyzed, including:

1. Reference scenario assumptions and assumption changes under alternative scenarios.
2. Justification or context for assumption changes.
3. The sensitivities used for each scenario.
4. Discussion of the required resources under each scenario.

H. Proposed Course of Action

The filing shall identify the projected need for future energy resources due to load growth, changes to existing or available resources, legislative mandates, Commission orders, or other reasons identified during the integrated resource planning process and shall present the course of action which is considered to best satisfy those needs through the application of reliable and cost-effective measures with due consideration of the associated benefits and risk.

The proposed course of action shall include a description of the resources required for the plan, expected costs of the proposed resource additions, and tabular summaries of: the reference case results, the expansion plan timeline identified by the IRP, estimated yearly energy production by fuel type, a comparison of the projected present value of revenue requirements for future fixed cost expenditures associated with each proposed supply resource, and future variable cost expenses associated with meeting customer energy requirements for each alternative scenario over the course of the planning period. Sample Tables H-1 through H-5 have been provided for illustrative purposes. The IRP shall also present an estimated calculation of average customer rates as a result of the plan.

Proposed Course of Action Summary	
Assumption Summary	
Expected Annual Increase in Peak Demand (Without Plan)	
Expected Annual Increase in Customer Energy Requirements (Without Plan)	
Required Reserve Margin (%)	
Renewable Portfolio Standard Requirements	
Energy Efficiency Requirements	
CO_2 Rules and Regulations	
Planned Changes to Capacity	
Additional Considerations	
…	
…	
Capacity Additions	
Supply Resource I (MW)	
Supply Resource II (MW)	
Supply Resource III (MW)	
Supply Resource IV (MW)	
Renewable Capacity (MW)	
Other (MW)	
TOTAL	
System Demand and Reserve Margin (With Plan)	
Annual Demand Growth (%)	
Annual Increase in Customer Energy Requirements (%)	
Reserve Margin With Plan (%)	
Plan Cost (Real Dollars - $YEAR)	
NPV incremental fixed and variable revenue requirements	

Sample Table H-1: Reference Case Summary

	Proposed Course of Action Capacity Expansion Plan by Planning Period Year (MW)									
RESOURCE	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	…	YEAR N-2	YEAR N-1	FINAL YEAR
Supply Resource I										
Supply Resource II										
Supply Resource III										
Supply Resource IV										
Renewable Capacity										
Demand Reduction Resource Impact										
TOTAL										

Sample Table H-2: Expansion Plan Timeline

	Proposed Course of Action Estimated Generation by Planning Period Year (GWh)									
FUEL/RESOURCE	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	…	YEAR N-2	YEAR N-1	FINAL YEAR
Coal										
Natural Gas										
Nuclear										
Hydro										
Renewables										
Energy Efficiency Impact										
Other										

Sample Table H-3: Projected Generation by Fuel

		Planned Resources						
		Supply Resources (MW)					*Demand Reduction Resources (MW)*	
Scenario Name		**Supply Resource I**	**Supply Resource II**	**Supply Resource III**	**Supply Resource IV**	**Renewable Capacity**	**Energy Efficiency**	**Load Management/ Demand Response**
Reference Scenario								
Sensitivity Analyses	Sensitivity 1							
	Sensitivity 2							
	Sensitivity 3							
	Sensitivity 4							
Alternate Scenario A								
Sensitivity Analyses	Sensitivity A1							
	Sensitivity A2							
	Sensitivity A3							
	Sensitivity A4							
Alternate Scenario B								
Sensitivity Analyses	Sensitivity B1							
	Sensitivity B2							
Alternate Scenario C								
Sensitivity Analyses	Sensitivity C1							
	Sensitivity C2							
	Sensitivity C3							
Alternate Scenario D								
Alternate Scenario E								

Sample Table H-4: Alternative Scenario Resource Comparison

		Planned Resource Summary					Costs
Scenario Name		**Capacity Added (Name Plate - MW)**	**Capacity Added (Firm- MW)**	**Net Demand Reduction (MW)**	**Peak Demand w/ Plan (MW)**	**Reserve Margin w/ Plan (%)**	**Projected PVRR ($REAL)**
Reference Scenario							
Sensitivity Analyses	Sensitivity 1						
	Sensitivity 2						
	Sensitivity 3						
	Sensitivity 4						
Alternate Scenario A							
Sensitivity Analyses	Sensitivity A1						
	Sensitivity A2						
	Sensitivity A3						
	Sensitivity A4						
Alternate Scenario B							
Sensitivity Analyses	Sensitivity B1						
	Sensitivity B2						
Alternate Scenario C							
Sensitivity Analyses	Sensitivity C1						
	Sensitivity C2						
	Sensitivity C3						
Alternate Scenario D							
Alternate Scenario E							

Sample Table H-5: Alternative Scenario Summary and PVRR Comparison

APPENDIX A – MCL 460.6S(11)

MCL 460.6s

THE COMMISSION SHALL ESTABLISH STANDARDS FOR AN INTEGRATED RESOURCE PLAN THAT SHALL BE FILED BY AN ELECTRIC UTILITY REQUESTING A CERTIFICATE OF NECESSITY UNDER THIS SECTION. AN INTEGRATED RESOURCE PLAN SHALL INCLUDE ALL OF THE FOLLOWING:

- **(A) A LONG-TERM FORECAST OF THE ELECTRIC UTILITY'S LOAD GROWTH UNDER VARIOUS REASONABLE SCENARIOS.**
- **(B) THE TYPE OF GENERATION TECHNOLOGY PROPOSED FOR THE GENERATION FACILITY AND THE PROPOSED CAPACITY OF THE GENERATION FACILITY, INCLUDING PROJECTED FUEL AND REGULATORY COSTS UNDER VARIOUS REASONABLE SCENARIOS.**
- **(C) PROJECTED ENERGY AND CAPACITY PURCHASED OR PRODUCED BY THE ELECTRIC UTILITY PURSUANT TO ANY RENEWABLE PORTFOLIO STANDARD.**
- **(D) PROJECTED ENERGY EFFICIENCY PROGRAM SAVINGS UNDER ANY ENERGY EFFICIENCY PROGRAM REQUIREMENTS AND THE PROJECTED COSTS FOR THAT PROGRAM.**
- **(E) PROJECTED LOAD MANAGEMENT AND DEMAND RESPONSE SAVINGS FOR THE ELECTRIC UTILITY AND THE PROJECTED COSTS FOR THOSE PROGRAMS.**
- **(F) AN ANALYSIS OF THE AVAILABILITY AND COSTS OF OTHER ELECTRIC RESOURCES THAT COULD DEFER, DISPLACE, OR PARTIALLY DISPLACE THE PROPOSED GENERATION FACILITY OR PURCHASED POWER AGREEMENT, INCLUDING ADDITIONAL RENEWABLE ENERGY, ENERGY EFFICIENCY PROGRAMS, LOAD MANAGEMENT, AND DEMAND RESPONSE, BEYOND THOSE AMOUNTS CONTAINED IN SUBDIVISIONS (C) TO (E).**
- **(G) ELECTRIC TRANSMISSION OPTIONS FOR THE ELECTRIC UTILITY.**

APPENDIX B – Statutory Compliance Matrix

The table below provides a correlation between the individual sections of the Integrated Resource Planning Guidelines and the requirements set forth by MCL 460.6s(11).

MCL 460.6s(11) Subdivision	Statutory Requirement	Corresponding IRP Guideline Section or Sections
(A)	A long-term forecast of the electric utility's load growth under various reasonable scenarios	0,B,G
(B)	The type of generation technology proposed for the Generation facility and the proposed capacity of the generation facility, including projected fuel and regulatory costs under various reasonable scenarios.	B,C,H
(C)	Projected energy and capacity purchased or produced by the electric utility pursuant to any renewable portfolio standard.	C,D,H
(D)	Projected energy efficiency program savings under any energy efficiency program requirements and the projected costs for that program	D
(E)	Projected load management and demand response savings for the electric utility and the projected costs for those programs.	D
(F)	An analysis of the availability and costs of other electric resources that could defer, displace, or partially displace the proposed generation facility or purchased power agreement, including additional renewable energy, energy efficiency programs, load management, and demand response, beyond those amounts contained in subdivisions (c) to (e).	C,D
(G)	Electric transmission options for the electric utility.	C

P R O O F   O F   S E R V I C E

STATE OF MICHIGAN)

Case No. U-15896

County of Ingham)

April M. Arman being duly sworn, deposes and says that on December 23, 2008 A.D. she served a copy of the attached Commission orders via E-Mail, to the persons as shown on the attached service list.

April M. Arman

Subscribed and sworn to before me
this 23rd day of December 2008

Sharron A. Allen
Notary Public, Ingham County, MI
My Commission Expires August 16, 2011

GAS & ELECTRIC

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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** (e-file paperless)

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF EATON)

TINA L. BIBBS, being first duly sworn, deposes and says that on **March 2, 2018,** she served a true copy of **Michigan Public Service Commission Staff's Initial Brief** upon the following parties **via e-mail only:**

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TINA L. BIBBS

Subscribed and sworn to before me
this **2nd** day of **March, 2018.**

Pamela A. Pung

Pamela A. Pung, Notary Public
State of Michigan, County of Clinton
Acting in the County of Eaton
My Commission Expires: 5-7-2018