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

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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

<u>Business as Usual Scenario</u>

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.
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> 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."
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> 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.
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> 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.

<u>Scenario 2</u>

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.

Recommended changes to Scenario No. 2

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.

<u>Public Hearings</u>

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.

<u>First Public Hearing</u>

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.

Third Public Hearing

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.

Discussion

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]

<u>Scenario #1</u>: 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.)

<u>Scenario #2</u>: 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.

<u>Scenario #3</u>: 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

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[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.

[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:
  - Resources outside MI – Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO).
  - 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.

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[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.

[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]

[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 sensitivity 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.

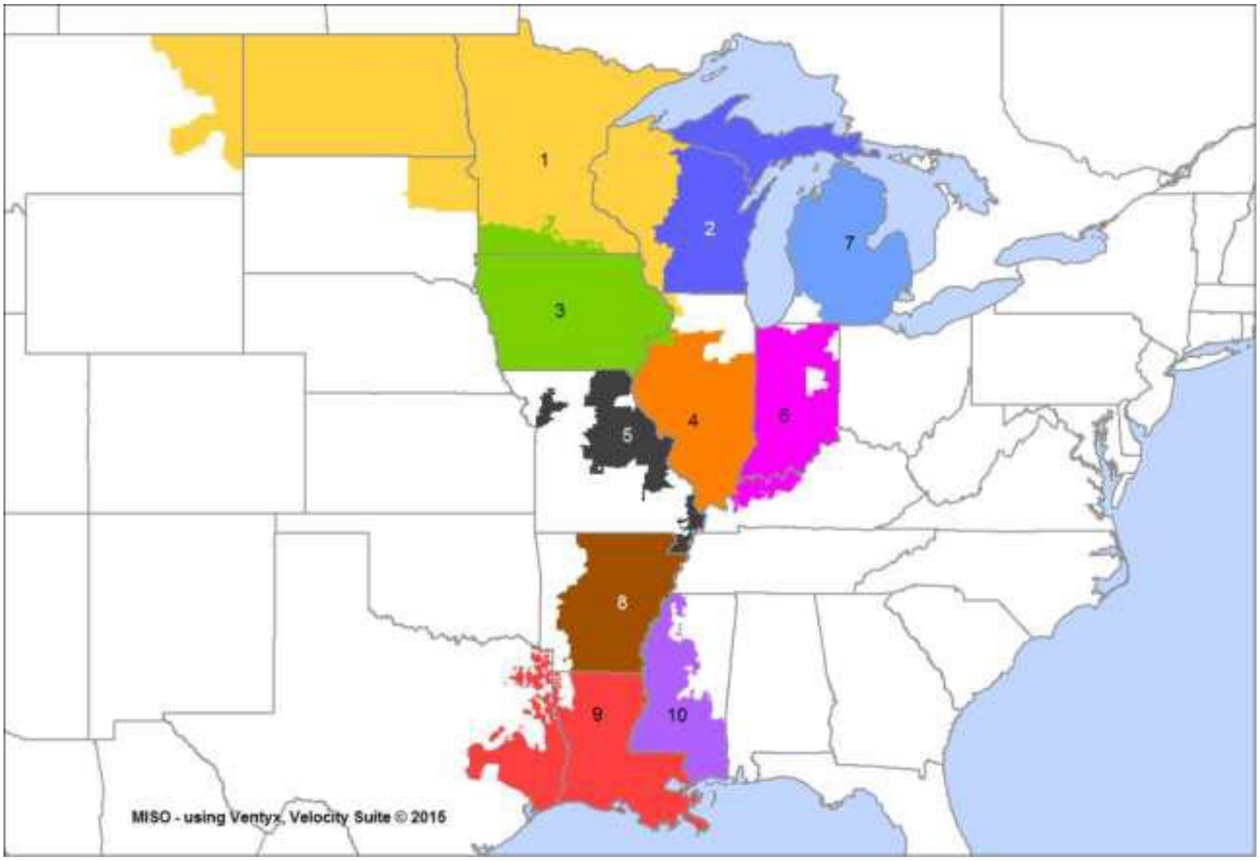
17. The IRP should consider any and all revenues expected to be earned by the utility's asset(s), as offsets to the net present value of revenue requirements.

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



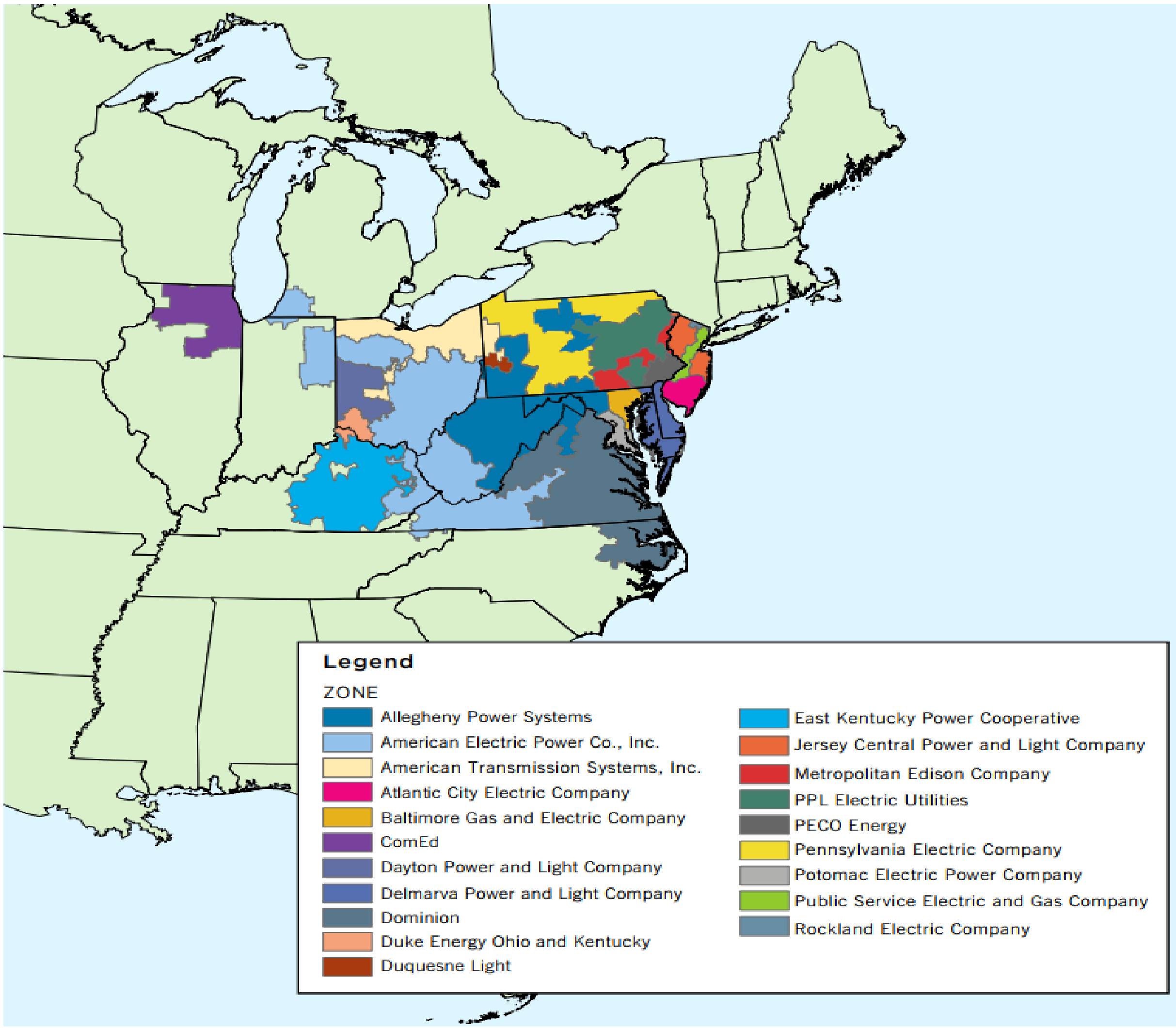
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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:

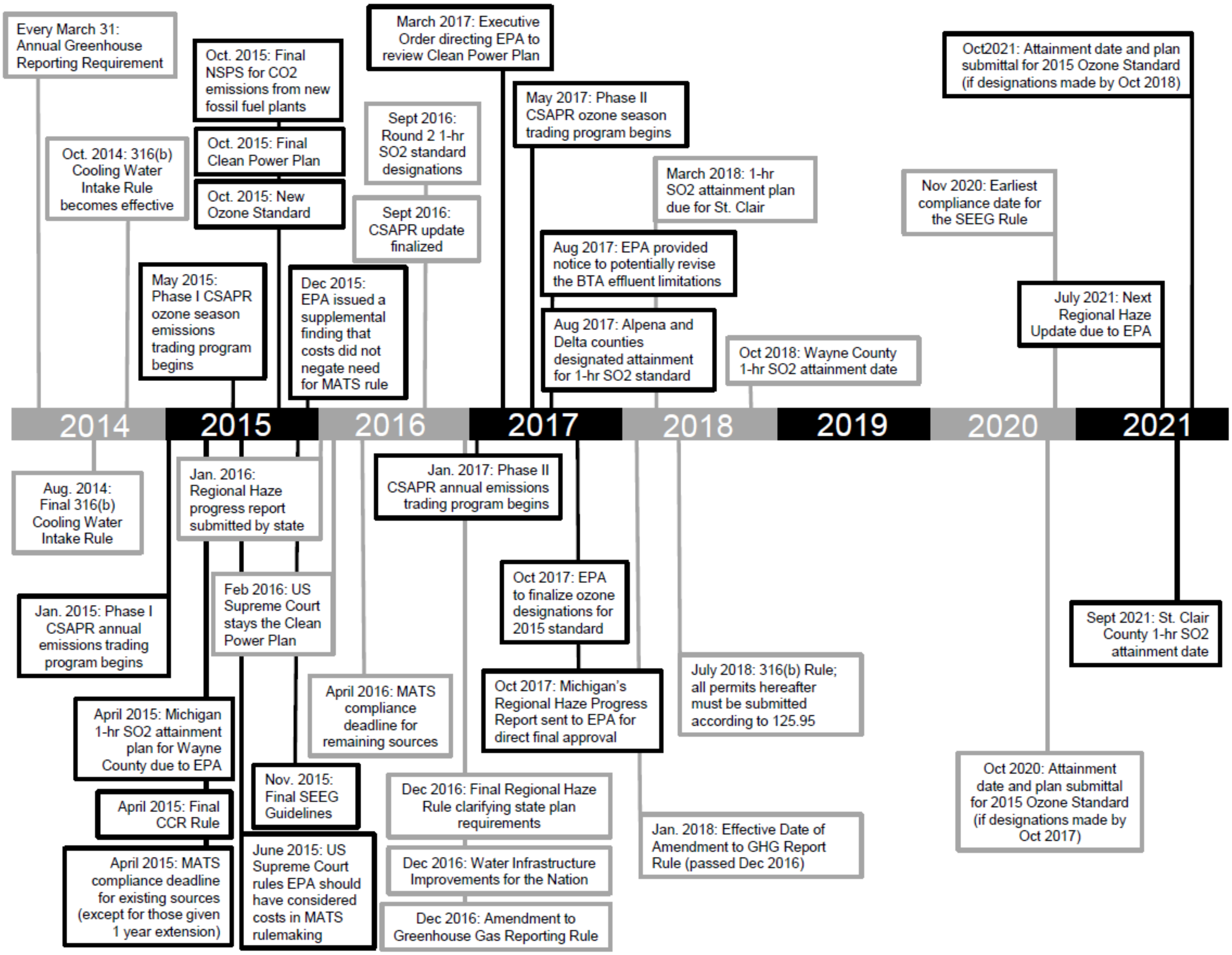
- (i) Any required planning reserve margins and local clearing requirements.
- (ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.
- (iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation 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



PROOF OF SERVICE

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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