MI Power Grid: Phase III Advanced Planning Processes

Feedback from April 26, 2022
Stakeholder Meeting

Consumers Energy
Count on Us®

May 16, 2022

VIA E-MAIL at GibbsK2@Michigan.gov

RE: Consumers Energy Comments to Staff on Michigan Integrated Resource Planning Parameters ("MIRPP") and Integrated Resource Plan ("IRP") Filing Requirements

Dear Ms. Gibbs:

The Company appreciates Staff's efforts leading the Advanced Planning Phase III workgroup collaborative discussions on April 26, 2022 and the presentations made by members of Staff. The Company thanks Staff for providing the opportunity for discussion and comment.

The Company requests consideration of the following comments in response to Staff prompts:

1. MIRPP

Please reference the attached Draft MIRPP redline document for feedback and recommended updates.

2. IRP Filing Requirements

Please reference the attached Draft IRP Filing Requirement redline document for feedback and recommended updates.

In conjunction with the provided redline, Consumers Energy would like to expand on the following feedback:

Regarding Appendix 1, paragraph VI, Consumers Energy continues to have the same concerns about the requirement to conduct air dispersion modeling as it has noted in its prior comments. Please see those prior comments for additional information. In particular, the Company wishes to again reiterate that it does not believe either the MPSC or EGLE has the legal authority to require dispersion modeling in the context of an IRP. It is very clear under the Clean Air Act, which is the foundation of EGLE's air quality regulations, that air dispersion modeling may be required only for a permit-to-install application associated with the installation of new emission sources, or certain physical modifications to existing emission sources.[1] Outside of this specific permitting context, EGLE cannot require air dispersion modeling. In fact, there are even some permitting contexts – like the renewal of a Renewable Operating

[1] *See*, *e.g.*, 40 CFR 51.160(f).

Permit – where EGLE cannot require dispersion modeling. As such, EGLE cannot require dispersion modeling in an IRP.[2]

Similarly, the MPSC cannot use its filing requirements to circumvent the restrictions in the Clean Air Act on when air dispersion modeling can be required. This position is inconsistent with the existing regulatory structure under the Clean Air Act, as noted above. We again caution the MPSC against putting itself in a shaky legal position by attempting to require what EGLE cannot require on its own.

3. Additional Comments

As expressed at the April 26, 2022 APW Phase III workgroup meeting, Consumers Energy is concerned with Staff's expressed intention to continue to revise the MIRPP and IRP Filing Requirements beyond the formal comment period that will follow this informal proceeding. The Company finds it crucial for transparency that the Commission allow comments on changes and then provide feedback on reasons for acceptance or denial of changes in response to comments. The Company requests Staff explain any changes that are adopted through this process. At a minimum, stakeholders should have an opportunity to comment on changes prior to the adoption of these standards.

Respectfully submitted,

Consumers Energy Company

[2] We also note that, if an IRP proposes a new emissions source, or a qualifying modification to an existing source, then air dispersion modeling can be conducted at the time of the permit application. Requiring before such an application is premature.

Integrated Resource Plan

Filing Requirements

Pursuant to Public Act 341 of 2016, Section 6t

Application Instructions for Integrated Resource Plan Filings

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

Schedule

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

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

Filing Announcement

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

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

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

The filing announcement shall include:

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

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

Pre-Filing Request for Proposals

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

a) The utility shall include with the IRP application documentation demonstrating that the RFP process was completed.
b) The utility's RFP process is subject to audit by the Staff.
c) The IRP filing shall include evidence that the pre-filing RFP process was conducted in a manner consistent with the ~~competitive procurement guidance in Case No. U-20852, the~~ Commission's code of conduct, and applicable state, federal, and Commission rules. To the extent that the Commission's competitive procurement guidelines are used in the pre-filing RFP, the IRP filing shall include an explanation of how the competitive procurement guidelines were used.

Commented [A1]: Proposed language. Previous language goes beyond what is required in the law, and the competitive procurement guidelines are not requirements but are only encouraged guidelines

d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, pursuant to MCL 460.6t(6).
e) The RFP shall allow for proposals to provide new supply-side capacity in the form of a purchase power agreement for a period that is the lesser of the study period or of the useful life of the resource type proposed.

Stakeholder Engagement and Public Outreach Process

Participant engagement early in the development of the IRP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decision-making process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.

In the 12 months prior to the IRP filing, each utility is encouraged to host update workshops with interested participants. The purpose of the pre-filing workshop(s) is to ensure that participants have the opportunity to provide input and stay informed regarding: (1) the assumptions, scenarios, and sensitivities; (2) the progress of the utility's IRP process; and (3) plans for the implementation of the proposed IRP. Documentation demonstrating the public outreach process undertaken by the utility shall be included with the IRP filing. Documentation may include:

a) Workshop dates and times, including times outside of the workday.
b) Evidence that a notice of the workshops was provided to the public.
c) Meeting minutes.
d) Meeting or workshop attendance lists.
e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application; and
f) Discussion indicating if or how the public outreach process influenced the IRP.
g) Include descriptions of community outreach efforts for vulnerable communities in the Company's service territory. Vulnerable communities should be identified using the MI EJ Screening Tool or

other tools as noted in the Section XVIII.

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

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

If the utility chooses to hold pre-filing workshops, including stakeholder engagement workshops or public meetings, the utility shall prepare a public outreach report to document the outcomes of any pre-filing workshops, and shall file the report with the IRP application.

All presentations, recordings, comments, and transcripts from those ~~presentations~~ presentations open the to public should be maintained on a website in a location open to the public for the duration of the stakeholder outreach process and the duration of the IRP case, until a final commission order is published.

Commented [A2]: The Company clarifies that the presentations and materials to be maintained on a public website are associated with presentations that were conducted as open to the public. Additional workshop materials from stakeholder meetings not open to the public will be filed with the stakeholder outreach report

Risk Assessment Methodology

The utility's IRP filing shall include a thorough risk analysis of the proposed resource plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the proposed resource plan and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies ~~and the PCA~~ for each scenario and the PCA to determine how each strategy would perform in an unexpected range of possible futures. The risk assessment methodology should incorporate the potential impacts of climate change in the forecasts for input variables.[1,2] Utilities are encouraged to link variables that can be shown to ~~are correlat~~have correlation or dependencies with each other~~ed to or dependent upon one another~~. The IRP shall include a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent- based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.

Commented [A3]: Proposed language adjustments

Confidential Information

Transparency and the use of data that can be shared with the Commission, the Staff, and intervenors is encouraged. Proprietary, confidential, and other nonpublic materials used in the development of the forecasts, scenarios, or other aspects of the IRP shall be presented in such a way that the proprietary and confidential nature of the materials is preserved. The use of publicly available data and materials is encouraged in lieu of proprietary and confidential materials and claims that information is proprietary or confidential should be justified by the utility.

Inclusion of specific materials in the IRP filing may be contingent upon appropriate confidentiality agreements and protective orders. Proprietary, confidential, and other nonpublic materials filed as part of the IRP shall be clearly designated by the utility as confidential.

Definitions

The following definitions are provided to aid in ensuring consistency across planning processes.

Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system, either through connection to primary distribution lines or a customer meter. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system.

Commented [A4]: Proposed language adjustments

Non-Wires Alternatives - An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for

[1] https://glisa.umich.edu/summary-climate-information/
[2] https://ccr.nelson.wisc.edu/

distribution system upgrades.

Vulnerable, Disadvantaged, Underserved Communities – to be defined in coordination with EGLE. See Appendix (IV) below.

Demand-side Resources - Resources serving~~e~~ resource adequacy needs by reducing load, which reduces the need for additional generation including but not limited to EWR, DR, grid and software controls, b~~B~~ehind the meter resources, distribution connected storage, etc.

Co-Benefits – Benefits that are quantified as part of another planning or an evaluation process that are important to the justification of a resource included in the integrated resource plan. Examples include benefits to distribution planning or evaluation of multiple revenue streams.

Approval of Costs

For the Commission to specify the costs to be approved for the construction of or significant investment in supply or demand-side resources, or contractual agreements, excluding short-term market capacity purchases to meet state reliability mechanism capacity requirements, in accordance with MCL 460.6t(11) through (12), the followinginformation, data, and documents shall be provided:

I) For specific supply-side resources (inclusive of storage technologies) of less than 225 megawatts (MW) (this threshold shall be applied to the nameplate capacity of a project, not individual generators,storage facilities, etc.), that are planned to go into service within three years following the approval of the IRP, the following evidence (covering the lifespan of the project) shall be provided:
   a) A description of the plant size, type, and summary of engineering/design specifications. The description shall also include the following:
      i. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
      ii. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and
      iii. Annual depreciation on the capital investment.
   b) Projected annual return and income taxes on capital investment.
   c) The operation and maintenance (O&M) costs over the life of the

facility described as costs which are variable, in current dollars per kilowatt-hour (kWh), with expenses for fuel and non-fuel items indicated separately; and costs which are fixed, in current dollars per kilowatt.

d) Projected property taxes.
e) The rates of escalation of cost, including:
    i. Capital costs.
    ii. O&M costs which are variable and related to fuel.
    iii. O&M costs which are variable and unrelated to fuel.
    iv. O&M costs which are fixed.
f) The total annual average cost per kWh at projected loads in current dollars for each year of the plan for the proposed facility.
g) Equivalent availability factors, including both scheduled and forced outage rates.
h) Capacity factors for each year in the planning period.
i) Operation cycle (i.e., baseload, intermediate, or peaking), identifying expected hours per year of operation, number of starts per year, and cycling conditions for each year in the planning period.
j) Heat rates (efficiency) for various levels of operation.
k) Unit lifetime, both for accounting book purposes and engineering design purposes, with explanations of differences.
l) Lead time, separately identifying the estimated time required for engineering, permitting and licensing, design, construction and pre-commercial operation date testing.
m) Potential socioeconomic impacts, such as employment, for the local region of the proposed supply-side resource, construction of or significant investment in an electric generation facility, or the purchase of an existing electric generation facility.
n) Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.

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

a) Capital, operating and maintenance costs for renewable energy systems (including property taxes and insurance for renewable energy systems).
b) Financing costs.
c) Costs that are not otherwise recoverable in base rates including interconnection and substation costs.
d) Ancillary service costs.
e) Cost of purchased renewable energy credits (RECs) other than those purchased for non-compliance.
f) Cost of Contracts.
g) Expenses incurred as a result of governmental action including changes in tax or other laws.
h) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029.
i) Recovery to include the authorized rate of return on equity, which will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved (only through 2029).
j) Provide the following information in relation to renewable resource cost recovery:
    i. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and
    ii. Forecast through the end of the renewable plan period of the regulatory liability balance.
k) Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.
l) A general ~~description of the decommissioning process, costs, and how~~discussion of how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling for proposed new renewable resources, including potential decommissioning process and costs.

Commented [A5]: Renewable resources requested for cost of approval can be 25 year or longer assets, making this requirement highly speculative with regards to both process and cost information that would be included in the regulatory filing. Alternative language is provided that would still support information being included in the filing, but not require information that is not available at the time of filing

III) Energy Waste Reduction: The utility shall providethe following information in relation to energy waste reduction programs cost approval and recovery. For each individual program or group of programs,provide:

a) Total annual cost including:
   i. Annual O&M cost for each individual portfolio of energy waste reduction programs.
   ii. Annual capital cost for each individual portfolio of energy waste reduction.
   iii. Expected cost-sharing or financial incentive granted to the utility by the Commission.
b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable.
c) Maximum single event demand reduction.
d) Total resource capacity (MW) and type reported to theapplicable regional transmission organization (RTO)/independent system operator (ISO).
e) Total energy reduction achieved in megawatt-hours (MWh).
f) Description of program, including customer enrollment, technology used, and marketing plan.

IV) Demand Response and DER Programs:

The utility shall provide the following information in relation to demand response programs and DER programs cost approval and recovery. For each individual program or group of programs, provide:

a) Total annual cost including:
   i. Annual O&M cost for each individual program of demand response and DER programs.
   ii. Annual capital cost for each individual program of demand response and DER programs.
   iii. Expected cost-sharing or financial incentive granted to the utility by the Commission.
b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable.
c) Maximum single event demand reduction.
d) Total resource capacity (MW) and type (load modifying resource, emergency demand response, etc.) reported to the applicable

Commented [A6]: The Company does not believe this breakout is necessary for the purposes of selecting resources, as DR and DER resources can have cost approval structures similar to EWR as a group of programs or a portfolio. Program level cost breakdowns can be included in the filing for informational purposes, but it is still appropriate to treat these resources as a portfolio for the purpose of resource selection.

regional transmission organization (RTO)/independent system operator (ISO).

e) Total energy reduction achieved (megawatt-hours (MWh)); and

f) Description of program, including customer enrollment, technology used, and marketing plan.

Waivers and Process for Smaller and Multistate Utilities

An electric utility with fewer than 1,000,000 customers in this state may request a waiver to any portion of these IRP filing requirements. Any request for a waiver shall include a discussion and justification outlining why the waiver is warranted and in the best interest of its customers. Discussion and justification for the requested waiver shall include a description of the utility's current and forecasted energy and capacity needs, and its plan for meeting those needs over the upcoming ten years.

If the utility requires resolution of a waiver request prior to filing an IRP application, the utility shall file the waiver request no less than 60 days prior to the filing of the IRP application.

An electric utility with fewer than 1,000,000 customers in this state may request approval from the Commission to file an IRP jointly with other smaller utilities. Commission approval is required prior to filing a joint IRP.

A non-multistate Michigan electric utility serving fewer than 1,000,000 customers may elect to file an IRP, based on its specific circumstances, that deviates from these requirements, but that is subject to the Staff's ability to request supplemental information. The filing shall include an explanation of why the deviations are reasonable under its circumstances. The Commission shall review any such filings under the traditional "just and reasonable" standard.

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

IRP Filing, Data, and Documentation

The utility's IRP filing shall demonstrate compliance with MCL 460.6t and include the following items:

a) Letter of transmittal expressing commitment to the approved resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisitionstrategy, acknowledging that the utility reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.
b) Technical volume(s) that fully describe and document the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy.
c) The data and information requested in the Commission's IRP filing requirements included herein; and
d) Any other information deemed relevant by the utility.

The utility's IRP filing shall include an IRP document(s) and application information including testimony and exhibits that fully describes and documents the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy. To facilitate a similar format for each utility's application, the utility is encouraged to align its filing with this provided outline and include at least the following items:

I) Executive Summary:

An IRP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The executive summary shall be an informative non-technical description of the resource plan proposed by the utility and its resource acquisition strategy.The executive summary shall summarize the contents of the IRP document and shall include the following:

a) An overview of the planning period examined in the IRP analysis and application.
b) A brief introduction describing the utility, its existing facilities, new resources being proposed, and implementation strategy.
c) A summary of the state, federal, ISO, RTO resource adequacy

regulations applicable to the utility.

d) A summary of the analytical approach used in the utility's analysis and the types of new resources considered.

e) A description of how the analytical approach considered potential resource co-benefits from other planning processes such as distribution or transmission planning.

f) A summary of any retirement analysis performed.

g) A description of how the environmental justice analysis results influenced the utility's proposed course of action.

h) The Company shall include a graph that depicts a stacked bar graph that includes the RTO capacity credit[3] of all existing resources and PCA resource additions, color designated by resource type, that it will use to serve demand in each year for all planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin.

i) The Company shall include graph that depicts a stacked bar graph that includes the annual energy expected to be produced by all existing resources, PCA resource additions, and market purchases for each year of the planning horizon. The graph shall be color designated by resource type. The graph shall have a line representing expected demand over the length of the planning period.

j) The Company shall include graph that summarizes the total of each of the following pollutants projected using the PCA in the MIRPP Scenario 1 for each year of the planning horizon. A graph should be included for NOx, So2, CO, PM, Pb, Hg, VOC, CO2. The graph should also depict the utility's progress toward or achievement of State, Federal and utility announced goals or requirements by including annotations for those goals on the years they apply.

k) Any other information that would aid the public understanding of the utility's proposed resource plan.

II) Table of Filing Requirements.

The utility shall provide a table that clearly identifies the where in the filing

Commented [A7]: The Company disagrees with the inclusion of VOCs, CO, and lead if this graph is to include the totals of these pollutants for all resources, which include PPAs and MISO purchases. Attempting to forecast these pollutants for entities not owned by the company, and for MISO, is likely to be highly speculative and inaccurate, which will therefore not present the appropriate data to the public in an executive summary document

[3] For example, MISO Zonal Resource Credit.

it has met all of the filing requirements. It sh_all include locations in testimony, exhibits and workpapers.

III) Testimony Introduction:

The utility shall describe resource plans to satisfy at least the objectives and priorities identified in MCL 460.6t. The utility may identify and/or describe additional planning objectives that the resource plan will be designed to meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that consider the planning objectives and priorities. The introduction shall include the following:

a) General description of the utility's existing energy system, including:
   i. Net present value of utility revenue requirements,[2][4] with and without any financial performance incentives for demand-side resources.
   ~~ii. Revenue requirement of existing generation and power purchase agreements.~~
   ~~iii.~~ii. Summary of existing generation and power purchaseagreements by fuel type.
   ~~iv.~~iii. Utility's existing capacity resource mix.
   ~~v.~~iv. Utility's service territory and breakdown of customer classcomposition; and
   ~~vi.~~v. Description of planning period analyzed.
b) Statement of power need.
c) Identify and explain the basis for the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements, for each year of the analysis used in each scenario and sensitivity evaluated by the utility as part of the IRP process.
d) Market and regulatory environment influencing resource planning decisions:
   i. RTO market and state regulation structure if a multistate utility.
   ii. Potential changes to RTO capacity market.
   iii. Electric customer choice.
   iv. Transmission expansion.

Commented [A8]: This item is not needed. Revenue requirement for existing generation is approved in rate cases, and is not incremental to long term revenue requirements. PPA costs are accounted for in the net present value of revenue requirements listed above.

[4] [2]The assumed discount rate shall be included along with a justification for the assumed discount rate. Resultsshould be presented in nominal dollars

v. Environmental.
vi. Renewable portfolio standards; and
vii. Other.

e) IRP planning process; and
f) Stakeholder report.

IV) Analytical Approach:

a) Describe the modeling process, including the duration of the study;
b) The utility shall describe and identify how its model approach optimizes resources to meet load and demand throughout the year ~~for all times of the year~~ and for each year of the planning horizons. The utility shall, at a minimum, demonstrate that any proposed plan meets both a winter and summer reserve margin requirement by explaining ~~explain~~ how the model considers the seasonal and operational characteristics of all resource types, including monthly generation profiles, forced outages, derates, seasonal or limited availability of resources, etc. If a winter reserve margin is not formally defined, the utility shall explain and defend its methodology to demonstrate its portfolio can meet winter peak load and demand.
c) Describe and provide a justification for the risk analysis approach adopted from the Risk Assessment Methodology section:
    i. The utility shall describe and document its quantification of the risk that affects the evaluation of the various resource plan options.
    ii. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings affected its decision on a resource plan.
    iii. If multiple forms of risk assessment are presented the utility shall explain why certain risk variables could not be included in or are unsuited for one type of risk assessment or another. Considering a risk variable under multiple forms of risk assessment is not discouraged.
d) The utility shall describe and document the identification of risk variables and/or combinations of risk variables selected, their ranges, probabilities, ranking, and/or weighting that defines the risk quantification which the various resource plan options were judged; describe how these risk variables were judged to be appropriate and

Commented [A9]: The Company reiterates it proposed changes to this requirement from comments submitted after the February 28th workgroup meeting.

While supportive of considerations for seasonal planning, absent a finalized seasonal construct at the time of these requirement updates, it is more appropriate to demonstrate a portfolio's ability to meet a defined summer and winter peak as opposed to a more generic "for all times of the year" explain how these were determined; and describe themodeling tools and data sources employed during the capacity expansion, and other modeling processes.

e) Interactions between risk variables should be captured to the extent that it is practical. Evaluation of variables in isolation is acceptable so long as there exists a comprehensive evaluation of resource plans risks that captures interactions and shows overall risk of appropriate build plans. A comprehensive risk assessment should at least include optimized build plans from the required MIRPP scenarios for the proposed resource plan and any alternative resource plans presented by the utility.

V) Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities.
b) In addition to the utility's own scenarios and assumptions, the inclusion of the established modeling scenarios and assumptions in the MIRPP approved by the Commission in Case No. U-21219, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.

VI) Existing Supply-Side (Generation) Resources:

Detailed account of projected energy and capacity purchased or produced by the utility's owned and contracted resources, including cogeneration resources. Include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:

a) Overview.
b) Fossil-fueled generating units.
c) Nuclear generating units.
d) Hydroelectric generating units.
e) Renewable generating units.
f) Energy storage facilities.
g) Power purchase agreements: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource.
h) RTO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating

costs, etc.).

~~i) Spot market purchases and off-system sales.~~

Commented [A10]: The Company reiterates its recommendation to remove this item from future IRP filings as it is difficult to calculate and does not provide value to the proposed plan or filing

VII) Demand-Side Resources:

Historical and projected load management and demand response programs for the utility in terms of MW and Midcontinent Independent System Operator, Inc., Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and demand response events for each program. The following items are to be included:
   i. Description of current demand response and load management programs for the IRP study horizon, including the amount of load reductions and the expected hours of interruption per day, month, and year for each program.
   ii. Review the historic performance of existing demand-side programs in delivering benefits and how the utility used such information in its demand response resource decisions.
   iii. Describe the utility's method for determining whether to purchase energy rather than relying on demand response.
   iv. A description of any other programs the utility is considering that could potentially expand demand response resources, including expected load reductions and operating parameters.

VIII) Renewables and Renewable Portfolio Standards Goals:

Projected energy purchased or produced by the utility from renewable energy resources.

a) Describe how the electric provider will meet existing renewable energy standards. If the level of renewable energy purchased or produced is projected to drop over the planning periods, the utility must demonstrate why the reduction is in the best interest of ratepayers.
b) Specify whether the number of MWh of electricity used in the calculation of the renewable energy credit portfolio will be the previous 12-month period of weather-normalized retail sales or based on the average number of MWh of electricity sold by the electric provider annually during the previous three years to retail customers in this state.
c) Include the expected incremental cost of compliance with existing renewable energy standards for the required compliance period.

d) A description of how the electric provider's plan is consistent with the renewable energy goals required by the Michigan Legislature (e.g. 35% combined renewable energy and energy waste reduction goal by 2025);
e) Describe the options for customer-initiated renewable energy that will be offered by the electric provider and forecast sales of customer-initiated renewable energy.
f) Describe how the electric provider will meet the demand for customer-initiated renewable energy.

The following non-exhaustive list suggests several elements that may be included:

a) Sales forecast through 2021 for compliance with the renewable energy standard, through 2025 toward meeting the 35% goal, and through the study period.
b) Detailed resource plan:
    i. Describe the utility's planned renewable energy credit portfolio.
    ii. Forecast RECs obtained via Michigan incentive RECs.
    iii. Forecast expected compliance levels by year to meet the renewable portfolio targets.
    iv. Identify key assumptions used in developing these forecasts and the proposed resource portfolio.
    v. Identify risks which may drive performance to vary.

IX) Peak Demand and Energy Forecasts:

A long-term forecast of the utility's sales and peak demand under various reasonable scenarios. Include details regarding the utility's plan to eliminate energy waste, including the total amount of energy waste reduction expected to be achieved annually, and the cost of the plan:

a) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.
b) Subsections:
    i. Key variables used to develop forecast.

ii. Long-term forecasting methodology.
iii. Forecasting uncertainty and risks.
iv. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers).
v. Base Case deliveries and demand forecast.
vi. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. U-21219, or subsequent Commission orders relating to IRP modeling parameters and requirements.
vii. Include detailed information about how the forecasts used for IRP modeling align with forecasts used for distribution planning.
viii. Detail information about distributed energy resource adoption and operation.
ix. Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts.
x. Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts.

X) Capacity and Reliability Requirements:

The utility shall indicate how it complies, and will comply, with all finalized state federal, ISO, RTO capacity and reliability regulations, laws, rules and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including the projected costs/revenues of complying with those regulations, laws, and rules. The utility shall identify any finalized changes to the applicable state, federal, ISO, or RTO capacity and reliability regulations, laws, rules and requirements that have occurred since its last IRP filing, including narrative that identifies how its PCA satisfies those requirements. The utility shall include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation foreach facility in the portfolio.

Commented [A11]: Spelling correction

XI) Transmission Analysis:

In accordance with MCL 460.6t(5)(h), the utility shall work with their local transmission owner to include an analysis ofpotential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:

a) The utility shall work with their local transmission owner to assess the need to construct new or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options.
b) In collaboration with their incumbent transmission owner, include an analysis of any co-benefits of storage, specifically the transmission system benefits associated with transmission interconnected storage that is not designated as a storage as transmission only asset.
c) A detailed description of the utility's efforts to engage local transmission owners throughout the utility's IRP process. To inform the IRP process and assumptions, a meeting schedule should ~~be~~ be determined that supports engagement throughout the process ~~set in advance~~. The filing should include the ~~pre-decided~~ meeting schedule that was determined, ~~any documentation that supports requested extensions of the initial pre-decided timing~~, any necessary changes to meeting frequency that were required and the reasons for the change, and a summary of meetings that ~~ultimately~~ took place throughout the process~~.~~
d) Detailed meeting minutes for utility/transmission owner meetings should include any requested studies, discussions about assumptions and any conclusions made during the meeting, alternatives that were reviewed, any other pertinent information that can be made public or provided through typical contested case confidentiality agreements.
e) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns.
f) Any information provided by their local transmission owner indicating theanticipated effects of fleet changes proposed in the IRP on the ~~local resource zone's (LRZ) capacity import limit (CIL)~~ transmission system, including both generation retirements and newgeneration, subject to confidentiality provisions.

Commented [A12]: As stated in previously filed comments, it is not necessary to set the entire meeting schedule in advance as this is unlikely to be practical for either the utility or the transmission owner for the entirety of the IRP process

Any information provided by their local transmission owner, including costand timing, indicating potential transmission options that could impactthe utility's IRP by: (1) increasing a local resource zone's (LRZ) import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboringRTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources or demand-side resources; (5) estimated interconnection costs for new resources (6) potential siting locations that may provide transmission system benefits.

g) In collaboration with their local transmission owner, any information regarding (1) identification of system locations or regions where energy resources can interconnect to the transmission system with minimal transmission investment, (2) recent studies, to the extent that they are available, that indicate ways in which the capacity import or export capabilities can be increased or may change and the resulting impacts to the local clearing requirement.

~~h)~~ Any transmission studies performed by their local transmission owner that support the resource plan proposed by the utility.

~~i)~~h) In conjunction with the local transmission owner, provide an analysis of transmission costs for access to out of state resources conducted by either the RTO, transmission owner(s), and/or utility.

~~j)~~i) Provide RTO reports or web links to report locations that contain information relied upon to support transmission related model assumptions ~~or other IRP decisions~~.

Commented [A13]: Proposed language changes

Commented [A14]: As stated in comments filed in the initial draft of updated filing requirements, it is not necessary to set the entire meeting schedule in advance as this is unlikely to be practical for either the utility or the transmission owner for the entirety of the IRP process

Commented [A15]: Proposed language changes

XII) Fuel

The utility shall include the following:

a) Overview.
b) Natural gas price forecasts under the various scenarios.
c) Oil price forecasts under the various scenarios.
d) Coal price forecasts under the various scenarios.
e) Delivered natural gas prices to existing and new utility-owned

generating plants.

f) Delivered oil prices to existing and new utility-owned generating plants.
g) Delivered coal prices to existing and new utility-owned generating plants.
h) Projected annual fuel costs under the various scenarios; and
i) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new and existing generation facility.

XIII) Resource Screen:

Describe the utility's options of resources, including combinations of resources constructed as a single facility (such as storage combined with a generation source), to serve future electric load such as utilizing existing and planned resources, build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a power purchase agreement. The following sections shall discuss each option in detail and options shall be considered in combination to serve future electric load. As described below, workpapers with information on the costs of each resource option and combination of resource options shall be provided with the utility's filing:

a) Existing and planned resources.
b) New build:
    i. New generation technology and operating assumptions.
    ii. New generation development costs.
    iii. New energy integration of storage technology and operating assumptions; including all storage options.
    iv. New energy storage development costs.
    v. Development costs and operating assumptions for combinations of resources constructed as a single facility.
c) Distributed Energy Resources inclusive of non-wires alternatives identified in other planning processes.
d) Demand-side Resources inclusive of non-wires alternatives identified in other planning processes.
e) Market capacity purchases:
    i. Regional market supply outlook.
    ii. Availability of market capacity.
    iii. Market capacity price assumptions.

f) Long-term power purchase agreements.
g) Transmission resources:
   i. Overview.
   ii. Existing import and export capability.
   iii. Transmission network upgrade assumptions for the IRP; and
   iv. Import and export impact on resource strategy.

XIV) Modeling Results:

An analysis of the capital costs, energy production, energy production costs, fuel costs, energy served, capacity factor, emissions (levels and costs), and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state. The following suggest specific items to be included. They are not exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination).
b) Results for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that include annual revenue requirements, present value of annual revenue requirements and net present value of revenue requirements, and portfolio capacity including additions and retirements. Include monthly and annual energy pricing, and resource capacity and load factors.
c) Base case portfolio options to be selected from.
d) Analysis of IRP results.
e) Risk assessment presented with graphics and data that illustrate the results of any stochastic risk analysis performed ~~results~~ such that the probability distributions are clearly defined along with relative positions of the distributions so that plans can be directly compared on a single graph. The use of a box and whisker plot and/or efficient frontier plot is recommended.

Commented [A16]: Proposed language change

XV) Proposed Resource Plan

Include a detailed description of:

a) The type of generation technology proposed for a generation facility or combination of resources constructed as a single facility contained in the plan and the proposed capacity of the generation facility or combination of resources constructed as a single facility, including projected fuel costs under various reasonable scenarios.

b) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements.
c) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new generation facility; and
d) How the utility will meet local, state, and federal laws, rules, and regulations under the ~~proposed~~ proposed resource ~~course of action~~.

The utility shall describe the process used to select the proposed resource plan, including the planning principles used by the utility to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall describe how its proposed resource plan satisfies the following:

a) Strike an appropriate balance between the various planning objectives specified.
b) Utilize renewable and demand-side resources to comply with existing laws, goals and, in the judgment of the utility, are consistent withthe public interest to achieve state energy policies; and
c) In the judgment of the utility, the proposed resource plan, in conjunction with thedeployment of demand response measures, has sufficient resources toserve load forecasted for the implementation period.

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain:

a) A schedule to report the status of an approved plan in accordance with MCL 460.6t(14);
b) A schedule and description of actions to implement ongoing and planned

demand-side programs and demand-side rates.

c) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction.

d) An incremental net present value revenue requirement comparison of its proposal andreasonable alternatives over the planning period utilized in the analysis. It shall also include the calculation and comparison of the incremental net present value revenue requirement of the utility's proposed resource plan and any alternative resource plans including the alternative resource plans resulting from theCommission-approved modeling scenarios. In addition, the utility shall provide support for its chosen discount rate and discuss how the results of its analysis would change with different discount rate assumptions.

e) A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning (such as reliability and resilience benefits) when those benefits are unable to be captured through capacity expansion modeling runs, to the extent that the co-benefits were relied upon for justification of resource decisions.

f) A description of how, to the extent practical, the construction or investment in new resources in this state will be completed using a workforce composed of residents of this state.

g) A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state.

XVI) Rate Impact and Financial Information:

Projected year-on-year incremental impact of the proposed resource plan (and otherfeasible options) for the periods covered by the plan, covering the followingaccounts:

a) Revenue requirement.
b) Rate base.
c) Plant-in-service capital accounts.
d) Non-fuel, fixed operations and maintenance accounts.
e) Non-fuel, variable operations and maintenance accounts.
f) Fuel accounts.
g) Emissions cost.
h) Effluent additive costs; and

Commented [A17]: The Company reiterates from previous comments provided that it is most appropriate to present net present value of revenue requirements (NPVRR) in all instances, as the revenue requirement for existing generation is currently approved in utility rate cases, and therefore for IRP planning purposes it is more appropriate to call out incremental NPVRR to differentiate the impacts in potential resource plans

i) Projected change in generation plant-in-service.

The utility shall describe the financial assumptions and models used in the plan. The resource plan shall include, at a minimum, the following financial information,together with supporting documentation and justification:

a) The general rate of inflation.
b) The allowance for funds used during construction rates used in the plan.
c) The cost of capital rates used in the plan (debt, equity, and weighted) and the assumed capital structure.
d) The discount rates used in the calculations to determine present worth.
e) The tax rates used in the plan.
f) Incremental n~~N~~et present value of revenue requirements for the plan.
g) Nominal revenue requirements by year; and
h) Average system rates per kWh by year.

If the utility is proposing retirement of generation facilities that are expected to have an undepreciated book balance at the time of retirement, the utility shall include an analysis of various financing options for the remaining book balance if the utility is asking for specific treatment of the undepreciated book balance in its IRP. The utility shall:

a) include an analysis of various financing options for the remaining book balance.

b) identify the impact the different financing options have on the net present value revenue requirement of the proposed resource plan over the entire planning horizon.

~~c) provide detail to support how the financing treatment requested is the most reasonable and prudent financing means.~~

Commented [A18]: The Company objects to this language because it is inconsistent with the IRP law and legal standards applicable to proposals of this nature. Filing utilities also maintain the burden of proof for their proposals included in a regulatory proceed. If a utility seeking approval of a specific financing treatment, it will need to support it. Part (c) is therefore unnecessary and could only cause confusion.

XVII) Environmental Considerations and Environmental Justice:

Describe how the utility's resource plan and any alternative resource plans presented in the application will comply with all applicable local,state, and federal environmental regulations, laws, and rules:

a) Include a list of all environmental regulations that are applicable to the utility fleet. Identify which regulations apply to which resources.

b) Include all capital costs for compliance with new and reasonably expected environmental regulations for existing fleet assets in the utility IRP**.**

c) Include a chart that compares the total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify its use of a carbon counting methodology identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases.[5]

d) If the Company is proposing retirement of an existing resource, clearly identify the capital cost for environmental regulations and other capital investments in the facility. Costs that are identified as avoided capital costs shall also be identified as avoided capital costs due to becoming cost of removal, or fully avoidable capital costs.

e) Hold a technical conference with MPSC and EGLE staff within 30 days after the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers.

f) Provide emission data to inform the Department of Environment, Great Lakes, and Energy Advisory Opinion consistent with the specifications in Appendix A.

g) Identify, quantify and provide evidence in the filing that shows progress in meeting any state, federal or utility announced carbon reduction goals. Illustrate how each optimized build plan for each MIRPP scenario, the proposed resource plan, and the previously approved plan perform in meeting those goals throughout the planning period. [6] [7]

XVIII) Exhibits and Workpapers:

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[5] Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases[5], https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019

[6] Governor Gretchen Whitmer signed Executive Directive 2020-10 (ED 2020-10) regarding the urgent threat to the environment, economy, and the health and well-being of Michigan's residents posed by climate change and its implications. ED 2020-10 committed Michigan to pursuing a reduction of at least 26 to 28 percent in Greenhouse Gas (GHG) emissions below 2005 levels by 2025 and economy-wide carbon neutrality to be achieved no later than 2050 and maintained thereafter.

[7] April 22, 2021, President Joe Biden announced carbon reduction targets for the United States building upon carbon reductions to date. The new targets call for an economy-wide net GHG reduction of 50 to 52 percent from 2005 levels by 2030 and net zero GHG emissions economy-wide by no later than 2050.

The filing shall include exhibits and workpapers as outlined below, subject to any license or other confidentiality restrictions that are unable to be resolved by issuance of a protective order.

a) The Company shall include an exhibit containing a table that designates where each filing requirement is included within its testimony, exhibits, and workpapers with appropriate ~~page and~~ section numbers.

b) The Company shall include an exhibit that depicts a stacked bar graph that includes the RTO capacity credit of all existing resources and new resources for all scenarios and sensitivities, color designated by resource type, in each of the planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin.

c) The Company shall include an exhibit that depicts a series of stacked bar graphs that include the energy expected to be produced by all existing resources, new resources, and market purchases for each planning year and for all MIRPP required scenarios and sensitivities. Each graph shall be color designated by resource type. Each graph shall have a line representing expected demand over the length of the planning period.

d) Include a chart that compares the total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify which of the carbon counting methodologies it used for all scenarios and sensitivities. The methodology should be one identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases.[8]

e) Any workpapers used in developing the application, supporting testimony, and IRP. Such workpapers shall, when possible, be provided in electronic format with formulas intact.

f) Any modeling input and output files used in developing the application,

Commented [A19]: The Company recommends removing a requirement to list specific page numbers in the table, as formatting in the final submission of the testimony and exhibits into the docket can sometimes result in slight changes to page numbers, which then can create confusion with regards to page references listed in the table not matching where information is located

[8] https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019.

supporting testimony, resource plan, and any alternative plans. Such modeling input and output files shall, when possible, be provided in electronic format with formulas intact. The utility shall also identify each modeling program used and provide information for how interested parties can obtain access to such modeling program. Modeling inputs and outputs in the model-dependentbinary format should be made available to parties that obtain a license.

g) Cost data**,** estimates**,** and co-benefit analyses that were used in the resource screening process or in any other way to determine resource selection of each ~~electric~~ resource that was considered either individually or in combination with other resources constructed as a single facility, including distributed energy resources, storage, and renewable energy resources.

h) A description, including estimated costs of each alternative proposal received by the utility.

i) A discussion of any differences between its short-term fuel price forecasts and capacity price curve in the IRP filing, and the short-term fuel price forecasts and capacity price curve in its last power supply cost recovery proceeding.

j) Identification and justification of the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements used in the IRP. The utility shall identify its base case forecasts and a range of sensitivities for each such factor and explain how those sensitivities were identified. If the base case forecast(s) differs from recent previous forecasts submitted by the utility to the Commission in other cases, the utility shall provide an explanation for such differences.

k) Present an environmental compliance strategy which demonstrates how the utility will comply with all applicable federal and state environmental regulations, laws, and rules. Included with this information, the utility shall analyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's generation fleet.

l) Estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and over the life of the facilities included in their IRP.

m) The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates.

n) An analysis that contains an individualized cost estimate for electric resources that were considered, including renewable alternatives, such as solar, wind, or solar plus storage, and such cost estimates forall alternative proposals, solicited or unsolicited, received by the utility.

o) Electricity market forecasts utilized.

p) Other documents and data underlying the IRP analysis.

Appendix 1

I. Scope of Portfolio Build Plan Evaluated in Scenarios as follows (herein referred to collectively as portfolios):

   a. Portfolio 1: Previously approved portfolio (status quo; PCA in previously approved IRP) run in the MIRPP Scenario 1 (optimized through the current study period).
   b. Portfolio 2: Utility proposed course of action (PCA) portfolio run in MIRPP Scenario 1.
   c. Portfolio 3: Optimized portfolio in MIRPP Scenario 1.
   d. Portfolio 4: Optimized portfolio in Scenario 1 with high load sensitivity.
   e. Portfolio 5: Reasonable Alternatives to the PCA presented by the utility in MIRPP Scenario 1.

II. The utility will provide the following facility/unit level data and total annual fleet data, in an Excel spreadsheet(s) expressed in total tons, to EGLE for:

   a. Emissions of the following:
   b. sulfur dioxide (SO_2)
   c. nitrogen oxides (NO_x)
   d. carbon monoxide (CO)
   e. particulate matter (PM)
   f. lead (Pb)
   g. mercury (Hg)
   h. volatile organic carbon (VOC)
   i. carbon dioxide (CO_2)

These data will be presented as raw numbers/units and as the aggregate change comparing the three portfolios - #1, #2 and #5. The methodology used to determine the emissions from the respective regional transmission organization purchases will be explained. The utility will propose a sample template of what would be provided in the IRP filing to EGLE for agreement 30 days before the filing.

III. Analyze all portfolios to identify and quantitatively assess the potential impacts to vulnerable communities (as defined collaboratively with EGLE). The utility will perform an Environmental Justice Screening and Mapping Tool (EJSCREEN) or the Michigan Environmental Justice Screening Tool (Mi EJSCREEN). The screening will include vulnerable communities within a 3-mile radius of each facility for all facilities. This quantitative assessment should address air emissions and early retirement of fossil fuel-fired facilities. Explain how these considerations were considered in the utility's decision.

IV. Using the vulnerable communities identified in the analysis above, qualitatively assess the impacts of all portfolios including utility proposed early retirements of fossil fuel-fired facilities. The analysis should address water quality, waste disposal, and expected changes

Commented [A20]: A requirement to take a previously approved portfolio and run it through Scenario 1 actually creates an entirely new scenario for the IRP filing, as the assumptions are required to be updated and as stated this is going to result in a need for additional optimization to align with the new study period. A requirement to perform this modeling and include it in the filing creates that misalignments in comparisons that will result in being unable to do a true one-to-one comparison of a previously approved portfolio to an updated resource plan; this only creates confusion because differences will have to be explained qualitatively and cannot provide a clear picture.

The Company instead proposes that regression lines or other graphical representation that can show a comparison of emissions projections between different plans and compared against a previously approved IRP plan- this would not require the modeling of an entirely new scenario and still allow for emissions comparisons between plans.

in land use for new or retiring resources to the extent known at the time of filing.

V. To determine health impact estimates for air emissions, the utility will use the environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE), the Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool, or a similar analytical tool with mapping features and spatial resolution down to at least the county level. Based on the pollutant parameters compatible with the chosen tool, this air emissions data analysis will be performed to provide health impact estimates to assess:

a. Overall fleetwide health impacts of utility proposed early retirement of fossil fuel-fired facilities and renewable energy adoption. Results, including impacts and associated costs, will be presented for portfolios #1, #2, and #5.

b. Impacts on vulnerable communities identified above (within a 3-mile radius). Results, including impacts and associated costs, will be presented for all five listed portfolios.

VI. If a decrease in PM2.5 emissions is not demonstrated at all electric generating unit(s) within a 6-mile radius of an identified disadvantaged community, including any new proposed units that could reasonably be expected to locate within the 6-mile radius, conduct dispersion modeling for PM2.5 including all electric generating unit(s) within a 6-mile radius of the identified disadvantaged community. The current emissions should be used to establish a baseline modeling demonstration by which to compare the future impacts of portfolio #2. Any dispersion analysis conducted pursuant to this item, doesn't necessarily need to be a refined analysis. A screening analysis employing reasonable assumptions is acceptable. How refined the analysis is at the discretion of the utility. The goal of this analysis is to assess how the ambient concentrations of PM2.5 in vulnerable communities may be affected and to encourage an assessment of ambient impacts in the siting of any new units.

Commented [A21]: The company objects to this requirement as a whole as it goes beyond EGLE and MPSC authority.

VII. For resources located within the non-attainment areas, or an area that may be designated nonattainment based on reasonably known information at the time of filing, in the electric utility service territory, identify and assess their impact to the non-attainment status for the portfolio #2 listed above as compared to portfolio #1, and qualitatively support in testimony. The assessment should consider all nonattainment pollutants (i.e., SO_2 and ozone), as well as their precursors (i.e., NO_x and VOCs).

VIII. Narrative discussion of the quantitative and qualitative health and environmental impacts based on the analysis above, methodologies, data sources, and related observations. Explain how these considerations were considered in the utility's decision.

IX. Hold a technical conference with MPSC and EGLE staff within 30 days of the filing to discuss the environmental and emission related data included in the filing testimony, exhibits and workpapers.

DTE Electric Comments Regarding Staff's
MI Power Grid– Advanced Planning Phase III
May 16, 2022

On December 15, 2021, Michigan Public Service Commission's Staff prepared initial redlined Integrated Resource Planning (IRP) filing requirements and Michigan IRP Parameters (MIRPP). These were further discussed at the January 31st, February 28th, March 24th, and April 26th meetings.

DTE appreciates the effort of the Michigan Public Service Commission (MPSC), MPSC Staff (Staff) and all parties involved in this integrated planning collaborative.

Staff asked for feedback on the following:

1. Please provide any feedback supporting or suggesting changes to Staff's proposed MIRPP
2. Please provide any feedback supporting or suggesting changes to Staff's proposed Filing Requirements

#1 - MIRPP

Please see attached document 03 Phase III MIRPP Draft_Redline DTE Comments for comments and suggestions.

#2 - Filing Requirements

Please see attached document for 02 IRP Filing Requirements Draft_Redline DTE Comments for comments and suggestions

DTE looks forward to further discussions and collaboration with Staff and industry stakeholders on Michigan's integrated planning process.

DTE Energy

Draft 2022

Table of Contents

I. Executive Summary

This Michigan Integrated Resource Planning Parameters document was developed as a partof the implementation of the provisions of Public Act 341 of 2016 (PA 341), Section 6t. This document includes two integrated resource plan (IRP) modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Upper and Lower Peninsulas. 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 beviewed 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 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 and Energy Waste Reduction Potential Studies were completed August of 2021. Both studieshave an influence on integrated resource planning and are

incorporated into the Commission's Docket (Case No. U-21219[1]) for the 5-year update pursuant to 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. This is the first 5-year update. The next 120-day proceeding to conduct these assessments and gather input shouldcommence in July 2027.

II. Background

On December 21, 2016, PA 341 was signed 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 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 MPSCfor review and approval.

At the conclusion of a stakeholder process and issuance of draft Michigan Integrated Resource Planning Parameters (MIRPP), the Commission adopted the MIRPP on November 21, 2017, in Case No. U-18418.

Pursuant to PA 341, the MPSC and the Department of Environment, Great Lakes and Energy (EGLE) began a second collaborative process as part of MI Power Grid Phase II – Integration of Resource/Distribution/Transmission Planning on September 24, 2020, with state-wide participation from a wide-range of stakeholders (listed in Appendix A). On October 29, 2020, the Commission issued an order in Case No. U-20633 directing Staff to also work with stakeholder groups to determine how to update IRP planning parameters and filing requirement to take into account the goals set by Michigan's utilities and how

[1] Add link once we have a docket.

these goals align with the greenhouse gas emissions targets set by Governor Whitmer. Stakeholder sessions discussed many aspects of PA 341 Section 6t including:

i. Environmental Policy
ii. Forecasting
iii. Transmission
iv. The Regional Energy Market
v. Distributed Energy Resources
vi. Economic valuation
vii. Generation Diversity
viii. Risk Assessment

Stakeholders were invited to participate by providing comments and feedback during and after every stakeholder session. met regularly from December 2021 to late April 2022 to discuss how to update various subsections of PA 341 Section 6t. Further details on the stakeholder sessions are included on the MPSC's web page for Phase III of the MI Power Grid initiative.[2]

The Commission released an earlier draft of this document with a Commission Order initiating Case No. U-21219 on July, 2022. Interested parties were provided an opportunity to file comments and reply comments in Case No. U-21219. The Commission has considered the comments and reply comments and has incorporated several changes herein.

III. 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 conducted by Guidehouse Inc. (Guidehouse) for electricity and natural gas for the entire State of

[2] https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93320-508709--,00.html.

Michigan. This study's objective was to assess the potential in the residential, commercial, and industrial sectors, with the addition of small commercial, multifamily, and low-income segments, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. Measure and market characterization data was input into Guidehouse's Demand Side Management Simulator (DSMSim™) model, which calculates technical, economic, and achievable potential across utility service areas in Michigan for more than 600 measure permutations. Results were developed and are presented separately for the Lower and Upper Peninsulas. These results will be used to inform EWR goal setting and associated program design for the MPSC.[3]

Scenario #1: Reference–Estimates of achievable potential calibrated to 2021 total program expectations and refined using relative savings percentages at the end use and high impact measure-level with 2019 actual achievements. Key assumptions include non-low-income measure incentives of 40% of incremental cost (low-income segments incentivized at 100% of incremental cost) and administrative costs representing 33% of total utility program spending.

Scenario #2: Aggressive–Increased measure incentives and marketing factors and decreased program administrative costs. Analyzed measure incentive levels to determine the 1.0 Utility Cost Test (UCT) ratio tipping point. Developed measure-level incentive estimates based on these results and adjusted where necessary to ensure program-level cost effectiveness. Increased marketing factors above calibrated values for specific end use and sector combinations.

Scenario #3: Carbon Price–Acknowledging the regulatory uncertainty around carbon price legislation, provides a high-level fuel cost adder, ramping up through time as the probability of regulatory action increases. This scenario provides insight into the sensitivity of EWR savings potential to avoided costs. Due to the uncertain nature of carbon pricing legislation, the scenario is not related to specific program or policy recommendations.

[3] MI EWR Potential Study MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov), Retrieved December 8, 2021.

Increased electricity ($/MWh) and natural gas ($/therm) avoided costs by 50% in 2021, escalating with a 2.5% multiplier growth until a 100% increase was met.

IV. Demand Response Potential Study[4]

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

The MPSC issued a request for proposal for the DR potential study in May of 2020. Bids were received and evaluated and a contract for the study was awarded to Guidehouse Inc. in August of 2020. The DR potential study assessed DR potential in Michigan from 2021 to 2040 and was conducted in conjunction with the energy waste reduction (EWR) potential study. The DR potential study was completed in September of 2021.

The objective of the DR potential assessment was to estimate the potential for cost-effective DR as a capacity resource to reduce customer loads during peak summer periods. Additionally, the study assessed electric winter peak reduction potential and natural gas DR potential. DR potential estimates were developed for both the Lower Peninsula and the Upper Peninsula.

The DR potential and cost estimates were developed using a bottom-up analysis. The analysis used customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR program information from Michigan utilities, the latest available information from the industry on DR resource performance and costs. These sources provided input data to the model used to calculate total DR potential across Michigan.

The DR potential study was a collaborative process wherein the MPSC, Guidehouse, and stakeholders worked together to ensure the study reflected current Michigan market trends. Three virtual stakeholder meetings were held during the study which provided

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[4] 2021 Energy Waste Reduction and Demand Response Statewide Potential Study, https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/demand-response-potential-study/

stakeholders with an update on study progress and an opportunity to provide feedback to Guidehouse and MPSC Staff.

V. State and Federal Environmental Regulations, Laws and Rules

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

Section 460.6t (1) (c)

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 (USEPA) to set NAAQS for six criteria pollutants that havethe potential of harming human health or the environment. The NAAQS are rigorously vetted bythe scientific community, industry, public interest groups, and the public. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standardsare set at a level that is protective of human 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 everyfive years by the Clean Air Scientific Advisory Committee. The six criteria pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.[5]

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

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 notabide by the Clean Air Act requirements to reign in the emissions of the pollutants are subject toUSEPA 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 USEPA for approval into the State Implementation Plan (SIP), and ensuring attainment occurs bythe 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 USEPA strengthened the primary NAAQSfor SO_2, establishing a new 1-hour standard of 75 parts per billion (ppb).

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

In May 2016, Michigan Department of Environment, Great Lakes, and Energy (EGLE) submitted its SO2 State Implementation Plan (SIP) strategy for southern Wayne County to the USEPA for final approval. This SIP was the strategy for bringing the area into compliance with the health-based NAAQS for SO2. Due to a lawsuit related to a portion of the SIP, USEPA is pursuing a federal implementation plan (FIP) for the non-attainment area, the action of which is still underway. In January 2022, USEPA made the formal determination that southern Wayne County did not attain the SO2 NAAQS by the 2018 deadline.

USEPA is working to complete the FIP and expects that it will be available for public comment sometime in winter of 2022. Following the approval of the FIP, EGLE will work

to incorporate its provisions into the SO2 SIP. Once all of the elements of the SIP have been implemented, EGLE plans to pursue a redesignation request for southern Wayne County.

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.

To better understand the quality of the air in the non-attainment area, tow monitors were installed in the vicinity in November 2016. The monitoring data has consistently shown SO2 levels in the area to be below the SO2 NAAQS. The Clean Air Act allows a state to submit a Clean Data Determination (CDD) to the USEPA if air monitors show three consecutive years of attaining data in a non-attainment area. This action waives the requirement for the state to produce a SIP for the non-attainment area.

EGLE determined that the CDD criteria had been met for the St. Clair non-attainment area and submitted a CDD to USEPA in July 2020, waiving the SIP requirement for the area. EGLE's CDD was approved by USEPA in December 2021. Upon shutdown of the St. Clair Power Plant in May 2022, EGLE expects to submit a redesignation request to USEPA for the St. Clair County non-attainment area as well.

Round three designations were to address all remaining undesignated areas by December 31, 2017. The USEPA 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 USEPA 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, were also designated as unclassifiable/attainment.

Ozone Non-Attainment Areas: In 2015, the USEPA strengthened the primary NAAQS for ozone, establishing a new 8-hour standard of 70 ppb.

On August 3, 2018, Michigan was designated marginal non-attainment for the 2015 ozone NAAQS in four areas (ten counties) of the state. In southeast Michigan, the seven-county area encompassing Livingston, Macomb, Monroe, Oakland, St. Clair, Washtenaw, and Wayne counties and on the west-side, two partial counties including Allegan and Muskegon and one full county, Berrien were found to have design values[6] exceeding the new ozone NAAQS of 70 ppb. This classification established an attainment deadline and attainment plan submittal date of August 3, 2021. In addition to the requirement to attain by this deadline, there are also 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 attain the standard, monitoring values over the three-year period between 2018 and 2020 must have design values at or below the standard of 70 ppb.

In the fall of 2021, EGLE began working on a redesignation request for the seven-county southeast Michigan nonattainment area. Although design values for the three-year period between 2018 and 2020 did not show attainment with the 2015 ozone NAAQS, the design values for the three-year period between 2019 and 2021 did attain. The redesignation request was submitted to USEPA in January 2022, and approval is expected in late spring/early summer 2022. The three western non-attainment counties (partial Muskegon and Allegan and full county Berrien) did not attain the standard. It is expected that USEPA will reclassify or "bump up" those counties from marginal to moderate non-attainment. A reclassification from marginal to moderate extends the attainment deadline to August 2024; however, a classification of moderate requires additional actions to reduce emissions to attain the standard. Required moderate nonattainment planning elements include (but are not limited to) major source reasonably available control technology, 15% reasonable further progress, and an attainment demonstration.

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

[6] The design value is the three-year average of the 4th highest 8-hour ozone value)

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 governsthe 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 (April through October). 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. The USEPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May 2017. The state currently has Good Neighbor obligations for the 2015 ozone standard.

On March 15, 2021, USEPA finalized the revised CSAPR rule update for the 2008 ozone NAAQS. Starting with the 2021 ozone season, the revised rule reduced the emission budgets and therefore allocation of NOx allowances from power plants in 12 states, including Michigan. The revision includes adjusting these 12 states emissions budgets for each ozone season from 2021 through 2024.

EPA establishes that the revised CSAPR update will reduce NO_x emissions from power plants in 12 states in the eastern United States by 17,000 tons in 2021 compared to projections without the rule, yielding public health and climate benefits that are valued, on average, at up to $2.8 billion each year from 2021 to 2040.

Mercury and Air Toxics Standards – Section 302 of the Clean Air Act requires the USEPA 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 EGLE. In June 2015, the United States Supreme Court found that the USEPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the District of Columbia Circuit Court of

Appeals ruled that MATS may be enforced as the USEPA modifies the rule to comply with the United States Supreme Court decision. The deadline for MATS compliance forall electric generating units was April 16, 2016.

In December 2015, in response to the United States Supreme Court's direction, the USEPA published a proposed supplemental finding that a consideration of cost does not alter their previous determination that it is appropriate and necessary to regulate air toxic emissions from coal- and oil-fired EGUs. The proposed supplemental finding was based on an evaluation of several cost metrics relevant to the power sector and also considered public comments. USEPA found that the cost of compliance with MATS was reasonable and that the electric power industry could comply with MATS and maintain its ability to provide reliable electric power to consumers at a reasonable cost. USEPA's supplemental cost finding was finalized in April 2016.

In May 2020, USEPA completed a reconsideration of the April 2016 appropriate and necessary finding for the MATS, correcting flaws in the approach considering costs and benefits while ensuring that HAP emissions from power plants continue to be appropriately controlled. The agency also completed the CAA required residual risk and technology review for MATS. Following that reconsideration, USEPA concluded that the consideration of cost in the 2016 Supplemental Finding was flawed. Specifically, they found that what was described in the 2016 Supplemental Finding as the preferred approach, or "cost reasonableness test," did not meet the statute's requirements to fully consider costs and was an unreasonable interpretation of the CAA mandate. Power plants were already complying with the standards limiting emissions of mercury and other HAPs, and that final action leaves those emission limits in place and unchanged.

In January 2022 USEPA issued a proposal to reaffirm that it remains appropriate and necessary to regulate HAPs, including mercury, from power plants after considering cost. This action revokes the May 2020 finding that it was not appropriate and necessary to regulate coal- and oil-fired power plants under CAA Section 112 which covers toxic air pollutants. USEPA reviewed the 2020 finding and considered updated information on both the public health burden associated with HAP emissions from coal- and oil-fired power plants as well as the costs associated with reducing those emissions under the

MATS. After weighing the public risks posed by these emissions to particularly exposed and sensitive populations, against the costs of reducing HAP emissions, USEPA is proposing to conclude that it remains appropriate and necessary to regulate these emissions.

CAA 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 CAA for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the USEPA 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.[7]

CAA Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources - Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the CAA requires the USEPA to establish standards for certain existing industrial sources. The final Clean Power Plan (CPP), promulgated on October 23, 2015, addressed carbon dioxide emissions from EGUs. The CPP 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.[8]

On February 9, 2016, the United States Supreme Court issued five orders granting a stay ofthe Clean Power Plan pending judicial review. On March 28, 2017, President Trump signed anExecutive Order directing the USEPA 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

[7] 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.

[8] 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.

cases in abeyance pending the USEPA's review of both rules, including through the conclusion of any rulemaking process thatresults from that review.

On June 19, 2016, the USEPA promulgated the Affordable Clean Energy (ACE) Rule which replaced and repealed the Clean Power Plan. The ACE rule established emission guidelines for states to use in developing plans to limit carbon emissions at their coal-fired electric generating units (EGU); but did not establish specific carbon emission reduction goals. The ACE rule focused on an "inside the fence line" best system of emission reduction approach to emission reductions in the form of heat rate improvements at each EGU. On January 19, 2021, the United States Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it back to the USEPA for further proceedings consistent with the Court's ruling. On October 29, 2021, the United States Supreme Court agreed to grant a writ of certiorari for petitions for review of the January 2021 decision of the United States Court of Appeals for the District of Columbia Circuit to strike down USEPA's 2019 ACE Rule. Four pending petitions before the United States Supreme Court were filed earlier in 2021 by a coalition of nineteen states led by West Virginia, the State of North Dakota, the North American Coal Corporation, and Westmoreland Mining Holdings, LLC. The Supreme Court is expected to hear the four combined cases in its current term with a ruling expected in late spring or early summer 202~~1~~2.

Although there are not currently any rules regulating carbon emissions from existing Electric Generating Units (EGU); due to the USEPA's 2009 endangerment finding on greenhouse gasses, and in light of the current reduction goals on carbon neutrality at both state and federal levels, utilities should address their anticipated greenhouse gas emissions with those carbon neutrality reduction goals in mind.

Greenhouse Gas Reporting Program – The Greenhouse Gas Reporting Program (codifiedat 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 USEPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year. The USEPA 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 standardsfor 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 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 improvevisibility, 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 timeto 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, andammonia. 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 eachsource-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 thatmay 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 USEPA. In 2005, the USEPA published the guidelines for BART determinations. Michigan has met the initial BART determination requirements. In December 2016, the USEPA issued a final rule setting revised and clarifying requirements for periodic updatesin state plans. The next periodic update was due July 31, 2021. EGLE

has submitted the periodic update and it is currently being reviewed by USEPA. 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 **US**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 USEPA established requirements for the safe disposal of coal combustion residuals (CCR) produced at electric utilities and independent power producers. These requirements were established under Subtitle D of RCRA and apply to coal combustion residual landfills andsurface impoundments. Michigan electric utilities must comply with these regulations.

In July 2016, the USEPA Administrator signed a direct final rule and a companion proposal to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under Subtitle D (Non-hazardous solid waste). These revisions were completed in response to a partial vacatur ordered by the United States Court of Appeals for the District of Columbia Circuit on June 14, 2016. This direct final rule became effective on October 4, 2016.

In July 2018, the USEPA finalized certain revisions to the 2015 regulations for the disposal of CCR in landfills and surface impoundments to provide states with approved CCR permit programs under the Water Infrastructure Improvements for the Nation (WIIN) Act or USEPA (where USEPA is the permitting authority) the ability to use alternate performance standards and to revise the groundwater protection standards for four constituents in Appendix IV to part 257 for which maximum contaminant levels (MCLs) under the Safe Drinking Water Act had not been established. The revision also provided facilities which are triggered into closure by the regulations additional time to cease receiving waste and initiate closure. This additional time was meant to better align the CCR rule compliance

dates with the Effluent Limitations Guidelines and Standards Rule for the Steam Electric Power Generating Point Source Category.

In September 2020, the USEPA finalized amendments to the part 257 regulations. First, the USEPA finalized a change to the classification of compacted-soil lined or “clay-lined” surface impoundments from “lined” to “unlined” under § 257.71(a)(1)(i), which reflected the vacatur ordered in the Utility Solid Waste Activities Group (USWAG) decision. Secondly, USEPA finalized revisions to the initiation of closure deadlines for unlined CCR surface impoundments, and for units that failed the aquifer location restriction, found in §§ 257.101(a) and (b)(1). These revisions addressed the USWAG decisions with respect to all unlined and “clay-lined” impoundments, as well as revisions to the provisions that were remanded to the Agency for further reconsideration. Specifically, USEPA finalized a new deadline of April 11, 2021, for CCR units to cease receipt of waste and initiate closure because the unit was either an unlined or formerly “clay-lined” CCR surface impoundment (§ 257.101(a)) or failed the aquifer location standard (§ 257.101(b)(1)). With this action, USEPA also finalized revisions to the alternative closure provisions, § 257.103. The revisions granted facilities additional time to develop alternative capacity to manage their waste streams (both CCR and/or non-CCR), to achieve cease receipt of waste and initiate closure of their CCR surface impoundments.

In November 2020, the USEPA published the CCR Part B final rule which allowed a limited number of facilities to demonstrate to USEPA or a participating state director that, based on groundwater data and the design of a particular surface impoundment, the unit had and will continue to ensure there is no reasonable probability of adverse effects to human health and the environment. The regulations stated that facilities had until November 30, 2020 to submit applications to USEPA for approval, but given the effective date for the final rule was December 14, 2020, USEPA accepted revisions or applications until December 14, 2020.

In October 2020, USEPA issued an advanced notice of proposed rulemaking seeking input on inactive surface impoundments at inactive electric utilities, referred to as "legacy CCR surface impoundments". The information and data received will assist in the development of future regulations for these CCR units.

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 USEPA promulgated rules under Section 316(b) of theClean 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 USEPA 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 aclosed-cycle, recirculating cooling system.

Following a previously promulgated version of the rules and judicial remand, the regulationsfor 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. Therules do not specify national BTA standards for minimizing entrainment mortality, but instead require that EGLE establish the BTA entrainment requirements for a facility on a site-specificbasis. 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 mustprovide 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, facilitieswill need to achieve the impingement and entrainment mortality standards as soon as practicableaccording to the schedule of requirements set by EGLE 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 (ELG) 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 reviewchallenging the regulations were consolidated in the United States Court of Appeals for the FifthCircuit on December 8, 2015. On April 25, 2017, the USEPA issued an administrative stay of the compliance dates in the ELGs and standards rule that had not yet passed pending judicial review. In addition, the USEPA requested, and was granted, a 120-day stay of the litigation (until September 12, 2017) to allow the USEPA to consider the merits of the petitions for reconsideration of the Rule. On August 11, 2017, the USEPA provided notice that it would conduct a rulemaking to revise the new, more stringent BTA effluent limitations and Pretreatment Standards for Existing Sources in the 2015 rule that apply to bottom ash (BA) transport water and flue gas desulfurization wastewater (FGD). The EPA published the regulations on October 13, 2020, finalizing the revisions for these two wastewaters allowing for less costly technologies, a two-year extension of the compliance time frame and for meeting the requirements, and adding subcategories for both wastewaters. The subcategories included a voluntary incentive program for more restrictive limitations for FGD wastewaters with a longer compliance schedule, and an allowance that electric generating units that decommission by December 31, 2028, need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities. The earliest date for compliance with bottom ash and FGD wastewaters was set for October 13, 2021, but no later than December 31, 2025, unless the facility announces compliance with an optional program. In addition, the EPA published an announcement on August 3, 2021, on its decision to undertake additional rulemaking to again revise the SEEG. As part of the rulemaking process, the EPA will determine whether more stringent effluent limitations and standards are appropriate and consistent with the technology-forcing statutory scheme and the goals of the Clean Water Act. EPA intends to publish the proposed rulemaking for public comment in the fall of 2022. On September 18, 2017, the 120-day administrative stay was lifted postponing certain compliance deadlines. The earliest date for compliance with SEEG was November 1, 2020.

On August 31, 2020, USEPA finalized a rule revising the regulations for the Steam Electric Power Generating category (40 CFR Part 423). The rule revises requirements for two specific waste streams produced by steam electric power plants: FGD wastewater and BA transport water. In the revised rule, USEPA delays the compliance deadlines for BA transport water and FGD wastewater two years to December 31, 2025. In addition, the revised rule includes a voluntary incentive program that provides additional time, until December 31, 2028, for facilities that implement additional processes that achieve more stringent limitations and also has an allowance that electric generating units that decommission by December 31, 2028 need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities.

State Rules and Laws:
The majority of Michigan's environmental regulations/laws/acts were consolidated into the Natural Resources and Environmental Protection Act (NREPA) of 1994, Public Act 451 as amended (Act 451). Act 451 is organized into sections called "Parts" and serves "to protect the environment and natural resources of the state; to codify, revise, consolidate, and classify laws relating to the environment and natural resources of the state; to regulate the discharge of certain substances into the environment; to regulate the use of certain lands, waters, and other natural resources of the state; to protect the people's right to hunt and fish; to prescribe the powers and duties of certain state and local agencies and officials; to provide for certain charges, fees, assessments, and donations; to provide certain appropriations; to prescribe penalties and provide remedies; and to repeal acts and parts of acts."

Michigan Mercury Rule – The purpose of the Michigan Mercury Rule (MMR) is to regulatethe 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 CCR as a solid waste. It requires any CCR that will remain in place in asurface impoundment or landfill be subject to siting criteria, permitting and licensing of the disposal area, construction standards for the disposal area, groundwater monitoring, correctiveaction, and financial assurance and post-closure care for a 30-year period. The disposal facilityis required to maintain the financial assurance to conduct groundwater monitoring throughout the post-closure care 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 InfrastructureImprovements 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. Under the amendment, 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. In 2018, Part 115 was amended to include the majority of the RCRA regulations would be enforced by states and the CCR units would not be subject to the dual regulatory structure. In 2018, Part 115 was amended to include the majority of the RCRA rule, including the regulation of CCR surface impoundments used for

storage. Michigan's request for state program approval is currently under review by the USEPA.

To comply with PA 341 Section 6t (5) (m)
"How the utility will comply with all applicable state and federal environmental regulations, lawsand 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 ofcompliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's 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 theMichigan 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.

VI. 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 reservemargins 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 intolocal resource zones (Zones) with the majority of the Lower Peninsula in Zone 7 and the UpperPeninsula combined with a large portion of Wisconsin in Zone 2, as shown in Appendix B. Theunshaded 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.[9] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins 2022 through 2031" for the entire footprint.[10] MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report.[11] 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 the LOLE requirement while fully using the Capacity Import Limit for such."[12] The Local ClearingRequirement for each zone is reported annually with the MISO planning resource auction resultsin April.[13]

For the southwest corner of the Lower Peninsula, in PJM's territory,[14] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[15] PJM outlines requirements for an Installed Reserve Margin, similar to MISO's planning reserve margin on aninstalled capacity basis, and a Forecast Pool Requirement on an unforced capacity basis, similarto MISO's planning reserve margin on an unforced capacity basis. PJM also specifies 27 LocalDeliverability Areas somewhat similar to MISO's local resource zones.

[9] MISO 2022-2023 Loss of Load Expectation Study Report published on November 1, 2021

https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[10] 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.

[11] 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.

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

[13] MISO Planning Resource Auction results, April 2021

https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

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

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

PJM publishes a Reserve Requirement Study[16] annually in October containing the requirements for generator owners andload 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 capacitydemonstration 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 through2021. 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, toestablish 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 utilityIRP filings should be consistent with the requirements of the State Reliability Mechanism underSection 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiated to implement these provisions.

VII. 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, twomodeling scenarios are required. Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other

[16] PJM Reserve Requirement Study, October 2021.
https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx

jurisdictions. Due to the provisions in PA 341Section 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

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario directionally aligns with MISO's December 2021 Futures Report, Future 1 and reflects substantial achievement of state and utility announcements including generation retirements and environmental goals. This scenario incorporates 100% of utility integrated resource plan (IRP) retirement announcements and retirement assumptions throughout the MISO footprint, as identified in MISO Future 1. For the utility performing the analysis, the generation unit retirement assumptions may vary for only the generation units the utility has decision making authority. As subsequent MISO Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 1 of the December 2021 report may be used. This scenario assumes that CO2 emissions decline, driven by state goals and utility plans throughout the MISO footprint creating at least a 63% carbon reduction by 2040 from the baseline year of 2005 for the MISO region. ~~This trajectory of carbon reduction is expected to continue beyond 2040.~~ Carbon emissions continue to decline beyond 2040.

This scenario assumes that demand and energy growth are driven by existing economic factors, with moderate electric vehicle (EV) adoption and customer electrification, resulting in moderate MISO footprint wide demand and energy growth rates. Utilities ~~should~~ may use the most recent United States Energy Information Administration (EIA)

Commented [A1]: The Company recommends that this sentence be annotated with a footnote that indicates the "note" language on the following page – "**Note: Scenario 1 aligns with MISO Future 1 from the December 2021 MISO Futures Report. If, in the future, MISO Futures significantly change, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 1.*"

Commented [A2]: As stated in previous comments, the 63% is actually an output of MISO futures modeling, not a target, and therefore this is inconsistent interpretation of numbers if an individual modeling result in MISO should form the base goal in IRP MISO modeling for the next five years of IRP filings.

As this section states, subsequent MISO Futures Reports may be used in future IRPs as they are performed- those subsequently reports may not have the same carbon reduction result, and therefore the 63% becomes out of date

Commented [A3]: The MISO Futures currently tie to 2039 (simply because MISO performed a 20-year study that initiated in 2019). The Company agrees with a change to 2040, but the Company would like clarification regarding if Staff intends to maintain the CO2 reduction target tied to 2040? Specifically, the Company is confirming that the CO2 reduction target will remain tied to 2040, even if subsequent MISO Future reports' study end year is 2041 or 2043, for example.

Commented [A4]: Proposed language change

Commented [A5]: Proposed language change based on the next sentence stating that utility may use EV forecasts other than EIA AEO

Annual Energy Outlook (AEO) Reference Case[17] or other reputable source for forecasted EV adoption rates. If the utility does not use EIA AEO then the EV forecast information must be provided within the utility IRP filing. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change,[18] electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.

*Note: Scenario 1 aligns with MISO Future 1 from the December 2021 MISO Futures Report. If, in the future, MISO Futures significantly change, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 1.

- Natural gas prices utilized are consistent with the Reference Case projections from the United States Energy Information Administration's (EIA) most recent Annual Energy Outlook.[19]
- Moderate EV adoption and customer electrification result in moderate footprint-wide demand and energy growth. Within Michigan, EV and electrification forecasts should be blended with historical sales such that after 3 years, Michigan's load and demand increase reflects the source forecasts for EV and electrification technologies. Load profiles of EVs and electrification technologies should be clearly delineated and presented individually such that it is clear how they each impacted the overall energy and demand forecast. EV forecasts ~~should~~ may be based off the Reference Case in the most recent EIA AEO. If the utility does not use EIA AEO then the EV forecast information must be provided within the utility IRP

[17] Electric Vehicle adoption as forecasted in the most recent EIA AEO East North Central Census Region Reference Case, http://www.eia.gov/outlooks/aeo/tables_ref.php

[18] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[19] 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 include delivery costs from Henry Hub to the point of delivery.

filing. Electrification technology forecasts should be based off of either established proprietary forecasts or publicly available data.

- Resource assumptions: ~~Assume~~ MISO Future 1 retirements for existing thermal and nuclear generation resources published in the most recent Futures Report should be used when available along with recent public announcements. Specific new units will be modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON), IRP cost pre-approval, or signed generator interconnection agreement (GIA). ~~Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO) should also be used.~~ Generic new resources are assumed consistent with the scenario description, considering anticipated new resources currently in generation interconnection queue, and should be chosen based upon economics.
- 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 participating in the State EWR Program, 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.[20]
- Existing renewable energy and storage production tax credits and renewable energy and storage investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- ~~All storage resources are considered.~~ Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist.[21]
- Technology costs for thermal units and wind track with mid-range industry expectations.

Commented [A6]: Language change to reflect consistency with use of EV forecasts listed above

Commented [A7]: This sentence no longer seems necessary if using MISO Future 1 retirements directly

Commented [A8]: Clarification request – is "without any cap" meant to represent that EWR savings would be unrestricted and a cost curve created to match in this scenario?

Commented [A9]: Propose to strike- the subsequent statement that energy storage resources are modeled using best practices implies that the most appropriate storage resources would be considered. Use of the word "all" is too vague

[20] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)

[21] Staff Report in Case No. U-20633 issued, May 27, 2021 and adopted by the Commission in its September 24, 2021 order.

- Technology costs and limits to the total resource amount available for EWR and demandresponse programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Technology costs for solar, storage, and other emerging technologies decline with commercial experience consistent with NREL or other publicly available reputable sources.
- Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Scenario #1 Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections ~~at~~ by the end of the 20-year study period.[22]

Commented [A10]: Language added to reflect consistency in other parts of the MIRPP which specifically reference a 20-year study period

2. Load projections
   (a) High load growth: For the filing utility's load obligation, increase the energy and demand growth rates by at least a factor of two above the base case energy or 0.5% (whichever is larger) and demand growth rates on a per customer basis. For the region included in the scenario utilize load growth that is consistent with the most recent MISO futures.
   (b) Low load growth: EV adoption and electrification are slower than expected. Demand and load growth are consistent with 5-year historical growth rates prior to 2020 and the onset of COVID-19.

[22] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.

(c) 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 the demonstration year of the utility's next capacity demonstration filing. Assume that load is returned in two phases with the first half returning halfway through the 4-year forward demonstration period and the remainder returning in the demonstration year of the utility's next capacity demonstration filing. This sensitivity does not apply to utilities within an RTO that requires the incumbent utility to show capacity for choice load.

3. If the utility is not already achieving 2% EWR, ramp up the utility's EWR savings to at least 2.0% of prior year sales over the course of 3 years within the utility's Michigan jurisdiction. EWR savings remain at 2% throughout the 20-year study period.

Scenario #2

Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario aligns with the Miso's December 2021 Futures Report, Future 3. It incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met. This scenario incorporates the retirement announcements and assumptions throughout the MISO footprint, as identified in Future 3. As subsequent Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 3 of December 2021 Futures Report may be used*. ~~Market energy purchases are modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3.~~

Commented [A11]: Propose to strike- see below for suggested updated language

This scenario assumes significant advancements toward electrification that drives a total energy and demand annual growth rates to 1.71% and 1.41% respectively throughout the Eastern Interconnect. ~~Emissions decline, driven by state goals and utility plans throughout the MISO footprint, creating at least an 80% carbon reduction by 2040 from the baseline year of 2025 for the MISO region. For utilities operating in PJM, assume 80% carbon reduction by 2040 from the baseline year of 2005 for the PJM region. This trajectory of carbon reduction is expected to continue beyond 2040.Market energy purchases are~~

~~modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3.~~ Utilities should assume EV adoption reaches 50% of total vehicle sales by 2030 with a continuing trend toward 100% of vehicle sales continues throughout the study period. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change,[23] electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.

Commented [A12]: Propose to strike- see below for suggested updated language

Emissions decline, driven by state goals and utility plans throughout the MISO footprint, creating at least an 80% carbon reduction by 2040 from the baseline year of 2025 for the MISO region. For utilities operating in PJM, assume 80% carbon reduction by 2040 from the baseline year of 2005 for the PJM region. This trajectory of carbon reduction is expected to continue beyond 2040. Market energy ~~purchases~~transactions are modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3.

*Note: Scenario 2 aligns with MISO Future 3 from the December 2021 MISO Futures Report. If, in the future, MISO Futures significantly change, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 2.

Commented [A13]: Suggested reorganization of Scenario 2 narrative to summarize all CO2 discussion into one paragraph

- Natural gas prices utilized are consistent with Reference Case projections from the United States energy Information Administration's (EIA) most recent annual Energy Outlook. [24]
- Current demand response, energy efficiency, and utility distributed generation programsremain in place and additional growth in those programs would happen if

[23] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[24] 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.

they were economically selected by the model to help comply with the specified carbon reductions in this scenario.

- EV adoption and customer electrification cause adjustments in overall load profiles as electrification and EV's are adopted through the planning horizon consistent with the most recent MISO Future 3.
- Specific new units are modeled if under construction or with regulatory approval (i.e., IRP cost pre-approval, CON, or signed GIA).
- For electric utilities independently administering their own EWR program, maintain a 2% EWR savings. If the utility is not already at 2%, ramp up the utility's EWR savings to at least 2.0% of prior year sales over the course of 3 years, using EWR cost supply curves provided in the 2021 supplemental potential study for more aggressive potential. [25] EWR savings remain at 2% throughout the study period.
- Achieve and maintain a 50% renewable energy portfolio by 2030 and another 10% from other renewable resources such as voluntary green pricing and distributed generation.
- Existing renewable energy production and storage tax credits and renewable energy investment and storage tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- ~~All storage resources are considered.~~ Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist. Allow for multiple market revenue streams where applicable.
- Technology costs for wind, solar, storage and other renewables decline linearly with commercial experience and forecasted at levels resulting in a 30% reduction from Scenario 1 by the end of the 20-year study period.

Commented [A14]: Propose to strike- the subsequent statement that energy storage resources are modeled using best practices implies that the most appropriate storage resources would be considered. Use of the word "all" is too vague

[25] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)

- Existing renewable energy production and storage tax credits and renewable energy and storage investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Existing PURPA contracts are assumed to be renewed. Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Scenario #2 Sensitivities:

1. Fuel cost projections: Increase the natural gas fuel price projections from the base projections to at leastthe high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections by ~~at~~ the end of the study period. [26]
2. Assume all coal facilities in Michigan are retired by 2030 and Michigan electric sector meets an 80% carbon reduction from the 2005 baseline, modeled as a hard cap on the amount of carbon emissions.[27]
3. Remove the assumed RPS and assume that 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).

[26] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.

[27] Based upon ramping to a net zero carbon power sector by 2035 https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

4. For electric utilities independently administering its own EWR program, ramp up to 2.5% EWR savings based upon prior year sales within the utility's Michigan jurisdiction.

VIII. Michigan IRP Modeling Input Assumptions and Sources

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

	Value	Sources
1 - Analysis Period	• A minimum analysis period of 20 years, with reporting foryears 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 ifapplicable. 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 scenarioand/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 • Retirement assumptions throughout the MISO footprint are consistent with MISO futures development Future 1 and Future 3.

6 - Natural Gas Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity 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 andmade available to all intervening parties.
7 - Coal Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity 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 andmade available to all intervening parties.
8 - Fuel Oil Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity descriptions.	• If utility-specific data is utilized, it should be justified andmade available to all intervening parties.
9 - Energy Waste Reduction Savings MWhs	Base Case: • For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to loadforecast. • For non-incentive earning electric utility, mandated annualincremental savings (1.0%) as a net to load. • Not less than 35% of the state's electric needs should bemet through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3). EWR Base Case Sensitivities: • For savings beyond mandate, incorporate EWR as anoptimized generation resource. Emerging Technologies Scenario: • Ramp up EWR savings at least 2.0% over the course of four years, using EWR Cost Supply Curves provided in the2017 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 • 2021 Energy Waste Reduction Potential Study

10 - Energy Waste Reduction Costs nominal dollars per kWh (Program administrator costs only; participant costs are not to beincluded in this analysis.)	• Current average levelized costs as defined in 2016/2017Potential Studies and Supplemental Modeling reflecting aggressive and cost-effective program savings goals.	• [2021 Energy Waste Reduction Potential Study]
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 demandresponse as applicable to the scenario.	• As defined by 2021 Demand Response Potential Study
12 - Demand Response Costs nominal dollars per MW	• Costs/MW by program including all payments, credits, orshared savings awarded to the utility through regulatory incentive mechanism.	• As defined by 2021 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 kWhand 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, mustbe justified and made available to all intervening parties.
15 – Other Resources	• Changes to operation guides • Options which improve reliability (Storage, SVC, HVDC, CVR) • 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 wheresuch 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, other 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 tothose technologies' and options' presently unconventionalnature. 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. • Storage Resource information
16 - Wholesale Electric Prices		• Documentation for wholesale price forecast must beprovided to all intervening parties.
17 – Electric Vehicle Forecasts	Scenario 1 EIA AEO Reference Case Scenario 2 half of vehicle sales are electric by 2030	• EIA AEO Transportation

Commented [A15]: Please see Company comments in overall comment document regarding concerns with highlighted sections in these draft document that indicate Staff will continue to revise IRP requirements beyond this comment period and continued uncertainty regarding what information and resources will be contained in the docket

IX. 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 fromthe 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 as specified in the Michigan Integrated Plan Filing Requirements.
5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled overthe 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 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 goalof 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 efficiencycost 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 Scenario 1 and Scenario 2, the utilities shall consider and prescreen all 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.

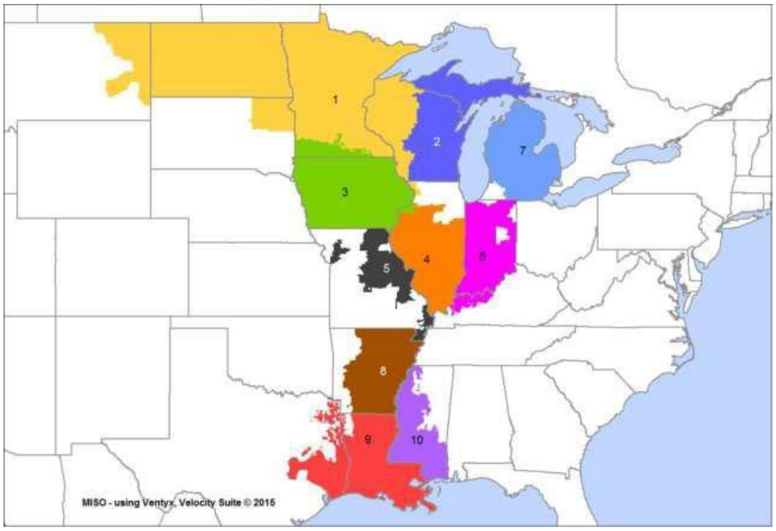
13. In modeling each scenario and sensitivity evaluated as part of the IRP process, the utility shall clearly identify all unit retirement assumptions and unless otherwise specified in the required scenarios, the utility has flexibility to allow the model to select retirement of the utility's existing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

14. To the extent that the utility is proposing early retirement of a generation facility (retirement that results in an undepreciated plant balance and prior to the end of the assumed useful life), the utility should present an NPVRR analysis that compares various financing options.
15. Recognize capacity and performance characteristics of variable resources.
16. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.
17. Take into consideration existing power purchase agreements, green pricing and/or other programs.
18. 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. The utility should explicitly identify revenues that are expected to be earn that are offsets to the net present value of revenue requirements and the assumptions that those revenues are based upon.
19. 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 thefollowing organizations or groups:

Update with Phase II and Phase III participants

Appendix B: Map of MISO Local Resource Zones



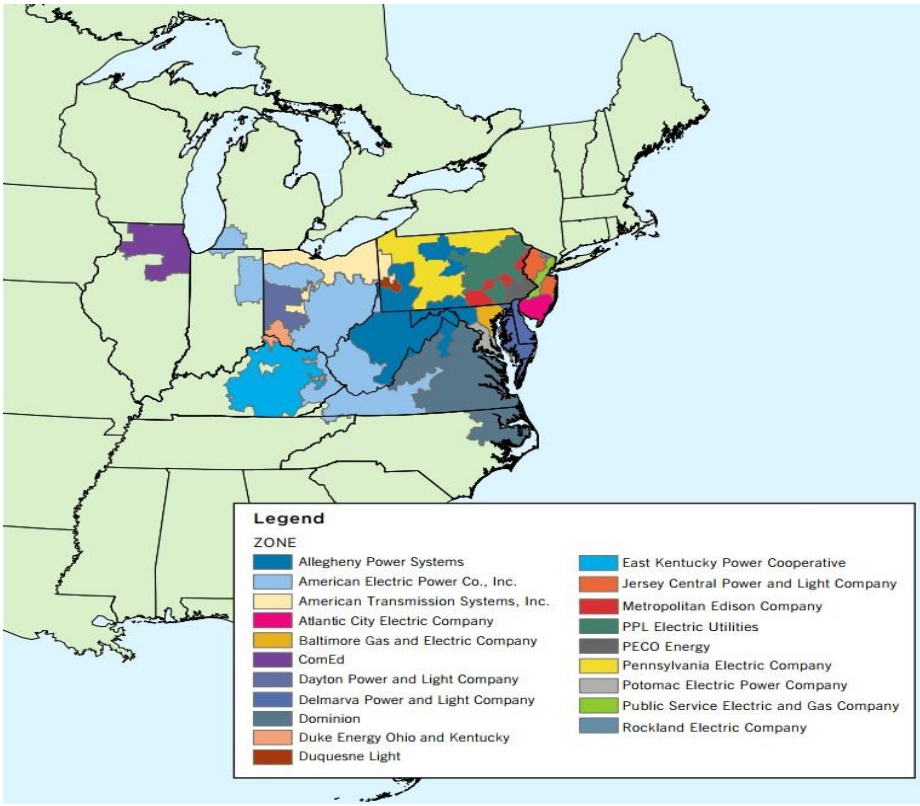
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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

MISO Zone 7 - Rate regulated electric utilities - Alpena Power Company, Consumers EnergyCompany, 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 ispart 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 the following as part of the proceeding:

(a) Conduct an assessment of the potential for energy waste reduction in this state, based on whatis 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 whatis economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already beeninstalled in this state and seek to fully maximize potential benefits to ratepayers in lowering utilitybills.

(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 additionto 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 foradditional 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 includein developing its integrated resource plan, receive written comments and hold hearings to solicitpublic input regarding the proposed modeling scenarios and assumptions.

Appendix E: Environmental Regulatory Timeline

- Updated chart forthcoming.

MICHIGAN INTEGRATED RESOURCE PLANNING PARAMETERS

Pursuant to Public Act 341 of 2016, Section 6t

Draft 2022

Table of Contents

I. Executive Summary

This Michigan Integrated Resource Planning Parameters document was developed as a partof the implementation of the provisions of Public Act 341 of 2016 (PA 341), Section 6t. This document includes two integrated resource plan (IRP) modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Upper and Lower Peninsulas. 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 beviewed 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 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 and Energy Waste Reduction Potential Studies were completed August of 2021. Both studieshave an influence on integrated resource planning and are

incorporated into the Commission's Docket (Case No. U-21219[1]) for the 5-year update pursuant to 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. This is the first 5-year update. The next 120-day proceeding to conduct these assessments and gather input shouldcommence in July 2027.

II. Background

On December 21, 2016, PA 341 was signed 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 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 MPSCfor review and approval.

At the conclusion of a stakeholder process and issuance of draft Michigan Integrated Resource Planning Parameters (MIRPP), the Commission adopted the MIRPP on November 21, 2017, in Case No. U-18418.

Pursuant to PA 341, the MPSC and the Department of Environment, Great Lakes and Energy (EGLE) began a second collaborative process as part of MI Power Grid Phase II – Integration of Resource/Distribution/Transmission Planning on September 24, 2020, with state-wide participation from a wide-range of stakeholders (listed in Appendix A). On October 29, 2020, the Commission issued an order in Case No. U-20633 directing Staff to also work with stakeholder groups to determine how to update IRP planning parameters and filing requirement to take into account the goals set by Michigan's utilities and how

[1] Add link once we have a docket.

these goals align with the greenhouse gas emissions targets set by Governor Whitmer. Stakeholder sessions discussed many aspects of PA 341 Section 6t including:

i. Environmental Policy
ii. Forecasting
iii. Transmission
iv. The Regional Energy Market
v. Distributed Energy Resources
vi. Economic valuation
vii. Generation Diversity
viii. Risk Assessment

Stakeholders were invited to participate by providing comments and feedback during and after every stakeholder session. met regularly from December 2021 to late April 2022 to discuss how to update various subsections of PA 341 Section 6t. Further details on the stakeholder sessions are included on the MPSC's web page for Phase III of the MI Power Grid initiative.[2]

The Commission released an earlier draft of this document with a Commission Order initiating Case No. U-21219 on July, 2022. Interested parties were provided an opportunity to file comments and reply comments in Case No. U-21219. The Commission has considered the comments and reply comments and has incorporated several changes herein.

III. 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 conducted by Guidehouse Inc. (Guidehouse) for electricity and natural gas for the entire State of

[2] https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93320-508709--,00.html.

Michigan. This study's objective was to assess the potential in the residential, commercial, and industrial sectors, with the addition of small commercial, multifamily, and low-income segments, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. Measure and market characterization data was input into Guidehouse's Demand Side Management Simulator (DSMSim™) model, which calculates technical, economic, and achievable potential across utility service areas in Michigan for more than 600 measure permutations. Results were developed and are presented separately for the Lower and Upper Peninsulas. These results will be used to inform EWR goal setting and associated program design for the MPSC.[3]

Scenario #1: Reference–Estimates of achievable potential calibrated to 2021 total program expectations and refined using relative savings percentages at the end use and high impact measure-level with 2019 actual achievements. Key assumptions include non-low-income measure incentives of 40% of incremental cost (low-income segments incentivized at 100% of incremental cost) and administrative costs representing 33% of total utility program spending.

Scenario #2: Aggressive–Increased measure incentives and marketing factors and decreased program administrative costs. Analyzed measure incentive levels to determine the 1.0 Utility Cost Test (UCT) ratio tipping point. Developed measure-level incentive estimates based on these results and adjusted where necessary to ensure program-level cost effectiveness. Increased marketing factors above calibrated values for specific end use and sector combinations.

Scenario #3: Carbon Price–Acknowledging the regulatory uncertainty around carbon price legislation, provides a high-level fuel cost adder, ramping up through time as the probability of regulatory action increases. This scenario provides insight into the sensitivity of EWR savings potential to avoided costs. Due to the uncertain nature of carbon pricing legislation, the scenario is not related to specific program or policy recommendations.

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[3] MI EWR Potential Study MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov), Retrieved December 8, 2021.

Increased electricity ($/MWh) and natural gas ($/therm) avoided costs by 50% in 2021, escalating with a 2.5% multiplier growth until a 100% increase was met.

IV. Demand Response Potential Study[4]

To comply with PA 341 Section 6t (1) (b)
The MPSC issued a request for proposal for the DR potential study in May of 2020. Bids were received and evaluated and a contract for the study was awarded to Guidehouse Inc. in August of 2020. The DR potential study assessed DR potential in Michigan from 2021 to 2040 and was conducted in conjunction with the energy waste reduction (EWR) potential study. The DR potential study was completed in September of 2021.

The objective of the DR potential assessment was to estimate the potential for cost-effective DR as a capacity resource to reduce customer loads during peak summer periods. Additionally, the study assessed electric winter peak reduction potential and natural gas DR potential. DR potential estimates were developed for both the Lower Peninsula and the Upper Peninsula.

The DR potential and cost estimates were developed using a bottom-up analysis. The analysis used customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR program information from Michigan utilities, the latest available information from the industry on DR resource performance and costs. These sources provided input data to the model used to calculate total DR potential across Michigan.

The DR potential study was a collaborative process wherein the MPSC, Guidehouse, and stakeholders worked together to ensure the study reflected current Michigan market trends. Three virtual stakeholder meetings were held during the study which provided

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[4] 2021 Energy Waste Reduction and Demand Response Statewide Potential Study, https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/demand-response-potential-study/

stakeholders with an update on study progress and an opportunity to provide feedback to Guidehouse and MPSC Staff.

V. State and Federal Environmental Regulations, Laws and Rules

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

Section 460.6t (1) (c)

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 (USEPA) to set NAAQS for six criteria pollutants that havethe potential of harming human health or the environment. The NAAQS are rigorously vetted bythe scientific community, industry, public interest groups, and the public. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standardsare set at a level that is protective of human 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 everyfive years by the Clean Air Scientific Advisory Committee. The six criteria pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.[5]

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

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 notabide by the Clean Air Act requirements to reign in the emissions of the pollutants are subject toUSEPA 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 USEPA for approval into the State Implementation Plan (SIP), and ensuring attainment occurs bythe 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 USEPA strengthened the primary NAAQSfor SO_2, establishing a new 1-hour standard of 75 parts per billion (ppb).

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

In May 2016, Michigan Department of Environment, Great Lakes, and Energy (EGLE) submitted its SO2 State Implementation Plan (SIP) strategy for southern Wayne County to the USEPA for final approval. This SIP was the strategy for bringing the area into compliance with the health-based NAAQS for SO2. Due to a lawsuit related to a portion of the SIP, USEPA is pursuing a federal implementation plan (FIP) for the non-attainment area, the action of which is still underway. In January 2022, USEPA made the formal determination that southern Wayne County did not attain the SO2 NAAQS by the 2018 deadline.

USEPA is working to complete the FIP and expects that it will be available for public comment sometime in winter of 2022. Following the approval of the FIP, EGLE will work

to incorporate its provisions into the SO2 SIP. Once all of the elements of the SIP have been implemented, EGLE plans to pursue a redesignation request for southern Wayne County.

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.

To better understand the quality of the air in the non-attainment area, tow monitors were installed in the vicinity in November 2016. The monitoring data has consistently shown SO2 levels in the area to be below the SO2 NAAQS. The Clean Air Act allows a state to submit a Clean Data Determination (CDD) to the USEPA if air monitors show three consecutive years of attaining data in a non-attainment area. This action waives the requirement for the state to produce a SIP for the non-attainment area.

EGLE determined that the CDD criteria had been met for the St. Clair non-attainment area and submitted a CDD to USEPA in July 2020, waiving the SIP requirement for the area. EGLE's CDD was approved by USEPA in December 2021. Upon shutdown of the St. Clair Power Plant in May 2022, EGLE expects to submit a redesignation request to USEPA for the St. Clair County non-attainment area as well.

Round three designations were to address all remaining undesignated areas by December 31, 2017. The USEPA 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 USEPA 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, were also designated as unclassifiable/attainment.

Ozone Non-Attainment Areas: In 2015, the USEPA strengthened the primary NAAQS for ozone, establishing a new 8-hour standard of 70 ppb.

On August 3, 2018, Michigan was designated marginal non-attainment for the 2015 ozone NAAQS in four areas (ten counties) of the state. In southeast Michigan, the seven-county area encompassing Livingston, Macomb, Monroe, Oakland, St. Clair, Washtenaw, and Wayne counties and on the west-side, two partial counties including Allegan and Muskegon and one full county, Berrien were found to have design values[6] exceeding the new ozone NAAQS of 70 ppb. This classification established an attainment deadline and attainment plan submittal date of August 3, 2021. In addition to the requirement to attain by this deadline, there are also 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 attain the standard, monitoring values over the three-year period between 2018 and 2020 must have design values at or below the standard of 70 ppb.

In the fall of 2021, EGLE began working on a redesignation request for the seven-county southeast Michigan nonattainment area. Although design values for the three-year period between 2018 and 2020 did not show attainment with the 2015 ozone NAAQS, the design values for the three-year period between 2019 and 2021 did attain. The redesignation request was submitted to USEPA in January 2022, and approval is expected in late spring/early summer 2022. The three western non-attainment counties (partial Muskegon and Allegan and full county Berrien) did not attain the standard. It is expected that USEPA will reclassify or "bump up" those counties from marginal to moderate non-attainment. A reclassification from marginal to moderate extends the attainment deadline to August 2024; however, a classification of moderate requires additional actions to reduce emissions to attain the standard. Required moderate nonattainment planning elements include (but are not limited to) major source reasonably available control technology, 15% reasonable further progress, and an attainment demonstration.

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

[6] The design value is the three-year average of the 4th highest 8-hour ozone value)

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 governsthe 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 (April through October). 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. The USEPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May 2017. The state currently has Good Neighbor obligations for the 2015 ozone standard.

On March 15, 2021, USEPA finalized the revised CSAPR rule update for the 2008 ozone NAAQS. Starting with the 2021 ozone season, the revised rule reduced the emission budgets and therefore allocation of NOx allowances from power plants in 12 states, including Michigan. The revision includes adjusting these 12 states emissions budgets for each ozone season from 2021 through 2024.

EPA establishes that the revised CSAPR update will reduce NO_x emissions from power plants in 12 states in the eastern United States by 17,000 tons in 2021 compared to projections without the rule, yielding public health and climate benefits that are valued, on average, at up to $2.8 billion each year from 2021 to 2040.

Mercury and Air Toxics Standards – Section 302 of the Clean Air Act requires the USEPA 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 EGLE. In June 2015, the United States Supreme Court found that the USEPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the District of Columbia Circuit Court of

Appeals ruled that MATS may be enforced as the USEPA modifies the rule to comply with the United States Supreme Court decision. The deadline for MATS compliance forall electric generating units was April 16, 2016.

In December 2015, in response to the United States Supreme Court's direction, the USEPA published a proposed supplemental finding that a consideration of cost does not alter their previous determination that it is appropriate and necessary to regulate air toxic emissions from coal- and oil-fired EGUs. The proposed supplemental finding was based on an evaluation of several cost metrics relevant to the power sector and also considered public comments. USEPA found that the cost of compliance with MATS was reasonable and that the electric power industry could comply with MATS and maintain its ability to provide reliable electric power to consumers at a reasonable cost. USEPA's supplemental cost finding was finalized in April 2016.

In May 2020, USEPA completed a reconsideration of the April 2016 appropriate and necessary finding for the MATS, correcting flaws in the approach considering costs and benefits while ensuring that HAP emissions from power plants continue to be appropriately controlled. The agency also completed the CAA required residual risk and technology review for MATS. Following that reconsideration, USEPA concluded that the consideration of cost in the 2016 Supplemental Finding was flawed. Specifically, they found that what was described in the 2016 Supplemental Finding as the preferred approach, or "cost reasonableness test," did not meet the statute's requirements to fully consider costs and was an unreasonable interpretation of the CAA mandate. Power plants were already complying with the standards limiting emissions of mercury and other HAPs, and that final action leaves those emission limits in place and unchanged.

In January 2022 USEPA issued a proposal to reaffirm that it remains appropriate and necessary to regulate HAPs, including mercury, from power plants after considering cost. This action revokes the May 2020 finding that it was not appropriate and necessary to regulate coal- and oil-fired power plants under CAA Section 112 which covers toxic air pollutants. USEPA reviewed the 2020 finding and considered updated information on both the public health burden associated with HAP emissions from coal- and oil-fired power plants as well as the costs associated with reducing those emissions under the

MATS. After weighing the public risks posed by these emissions to particularly exposed and sensitive populations, against the costs of reducing HAP emissions, USEPA is proposing to conclude that it remains appropriate and necessary to regulate these emissions.

CAA 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 CAA for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the USEPA 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.[7]

CAA Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources - Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the CAA requires the USEPA to establish standards for certain existing industrial sources. The final Clean Power Plan (CPP), promulgated on October 23, 2015, addressed carbon dioxide emissions from EGUs. The CPP 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.[8]

On February 9, 2016, the United States Supreme Court issued five orders granting a stay ofthe Clean Power Plan pending judicial review. On March 28, 2017, President Trump signed anExecutive Order directing the USEPA 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

[7] 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.

[8] 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.

cases in abeyance pending the USEPA's review of both rules, including through the conclusion of any rulemaking process thatresults from that review.

On June 19, 2016, the USEPA promulgated the Affordable Clean Energy (ACE) Rule which replaced and repealed the Clean Power Plan. The ACE rule established emission guidelines for states to use in developing plans to limit carbon emissions at their coal-fired electric generating units (EGU); but did not establish specific carbon emission reduction goals. The ACE rule focused on an "inside the fence line" best system of emission reduction approach to emission reductions in the form of heat rate improvements at each EGU. On January 19, 2021, the United States Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it back to the USEPA for further proceedings consistent with the Court's ruling. On October 29, 2021, the United States Supreme Court agreed to grant a writ of certiorari for petitions for review of the January 2021 decision of the United States Court of Appeals for the District of Columbia Circuit to strike down USEPA's 2019 ACE Rule. Four pending petitions before the United States Supreme Court were filed earlier in 2021 by a coalition of nineteen states led by West Virginia, the State of North Dakota, the North American Coal Corporation, and Westmoreland Mining Holdings, LLC. The Supreme Court is expected to hear the four combined cases in its current term with a ruling expected in late spring or early summer 202~~1~~2.

Although there are not currently any rules regulating carbon emissions from existing Electric Generating Units (EGU); due to the USEPA's 2009 endangerment finding on greenhouse gasses, and in light of the current reduction goals on carbon neutrality at both state and federal levels, utilities should address their anticipated greenhouse gas emissions with those carbon neutrality reduction goals in mind.

Greenhouse Gas Reporting Program – The Greenhouse Gas Reporting Program (codifiedat 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 USEPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year. The USEPA 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 standardsfor 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 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 improvevisibility, 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 timeto 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, andammonia. 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 eachsource-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 thatmay 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 USEPA. In 2005, the USEPA published the guidelines for BART determinations. Michigan has met the initial BART determination requirements. In December 2016, the USEPA issued a final rule setting revised and clarifying requirements for periodic updatesin state plans. The next periodic update was due July 31, 2021. EGLE

has submitted the periodic update and it is currently being reviewed by USEPA. 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 **US**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 USEPA established requirements for the safe disposal of coal combustion residuals (CCR) 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.

In July 2016, the USEPA Administrator signed a direct final rule and a companion proposal to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under Subtitle D (Non-hazardous solid waste). These revisions were completed in response to a partial vacatur ordered by the United States Court of Appeals for the District of Columbia Circuit on June 14, 2016. This direct final rule became effective on October 4, 2016.

In July 2018, the USEPA finalized certain revisions to the 2015 regulations for the disposal of CCR in landfills and surface impoundments to provide states with approved CCR permit programs under the Water Infrastructure Improvements for the Nation (WIIN) Act or USEPA (where USEPA is the permitting authority) the ability to use alternate performance standards and to revise the groundwater protection standards for four constituents in Appendix IV to part 257 for which maximum contaminant levels (MCLs) under the Safe Drinking Water Act had not been established. The revision also provided facilities which are triggered into closure by the regulations additional time to cease receiving waste and initiate closure. This additional time was meant to better align the CCR rule compliance

dates with the Effluent Limitations Guidelines and Standards Rule for the Steam Electric Power Generating Point Source Category.

In September 2020, the USEPA finalized amendments to the part 257 regulations. First, the USEPA finalized a change to the classification of compacted-soil lined or “clay-lined” surface impoundments from “lined” to “unlined” under § 257.71(a)(1)(i), which reflected the vacatur ordered in the Utility Solid Waste Activities Group (USWAG) decision. Secondly, USEPA finalized revisions to the initiation of closure deadlines for unlined CCR surface impoundments, and for units that failed the aquifer location restriction, found in §§ 257.101(a) and (b)(1). These revisions addressed the USWAG decisions with respect to all unlined and “clay-lined” impoundments, as well as revisions to the provisions that were remanded to the Agency for further reconsideration. Specifically, USEPA finalized a new deadline of April 11, 2021, for CCR units to cease receipt of waste and initiate closure because the unit was either an unlined or formerly “clay-lined” CCR surface impoundment (§ 257.101(a)) or failed the aquifer location standard (§ 257.101(b)(1)). With this action, USEPA also finalized revisions to the alternative closure provisions, § 257.103. The revisions granted facilities additional time to develop alternative capacity to manage their waste streams (both CCR and/or non-CCR), to achieve cease receipt of waste and initiate closure of their CCR surface impoundments.

In November 2020, the USEPA published the CCR Part B final rule which allowed a limited number of facilities to demonstrate to USEPA or a participating state director that, based on groundwater data and the design of a particular surface impoundment, the unit had and will continue to ensure there is no reasonable probability of adverse effects to human health and the environment. The regulations stated that facilities had until November 30, 2020 to submit applications to USEPA for approval, but given the effective date for the final rule was December 14, 2020, USEPA accepted revisions or applications until December 14, 2020.

In October 2020, USEPA issued an advanced notice of proposed rulemaking seeking input on inactive surface impoundments at inactive electric utilities, referred to as "legacy CCR surface impoundments". The information and data received will assist in the development of future regulations for these CCR units.

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 USEPA promulgated rules under Section 316(b) of theClean 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 USEPA 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 aclosed-cycle, recirculating cooling system.

Following a previously promulgated version of the rules and judicial remand, the regulationsfor 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. Therules do not specify national BTA standards for minimizing entrainment mortality, but instead require that EGLE establish the BTA entrainment requirements for a facility on a site-specificbasis. 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 mustprovide 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, facilitieswill need to achieve the impingement and entrainment mortality standards as soon as practicableaccording to the schedule of requirements set by EGLE 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 (ELG) 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 reviewchallenging the regulations were consolidated in the United States Court of Appeals for the FifthCircuit on December 8, 2015. On April 25, 2017, the USEPA issued an administrative stay of the compliance dates in the ELGs and standards rule that had not yet passed pending judicial review. In addition, the USEPA requested, and was granted, a 120-day stay of the litigation (until September 12, 2017) to allow the USEPA to consider the merits of the petitions for reconsideration of the Rule. On August 11, 2017, the USEPA provided notice that it would conduct a rulemaking to revise the new, more stringent BTA effluent limitations and Pretreatment Standards for Existing Sources in the 2015 rule that apply to bottom ash (BA) transport water and flue gas desulfurization wastewater (FGD). The EPA published the regulations on October 13, 2020, finalizing the revisions for these two wastewaters allowing for less costly technologies, a two-year extension of the compliance time frame and for meeting the requirements, and adding subcategories for both wastewaters. The subcategories included a voluntary incentive program for more restrictive limitations for FGD wastewaters with a longer compliance schedule, and an allowance that electric generating units that decommission by December 31, 2028, need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities. The earliest date for compliance with bottom ash and FGD wastewaters was set for October 13, 2021, but no later than December 31, 2025, unless the facility announces compliance with an optional program. In addition, the EPA published an announcement on August 3, 2021, on its decision to undertake additional rulemaking to again revise the SEEG. As part of the rulemaking process, the EPA will determine whether more stringent effluent limitations and standards are appropriate and consistent with the technology-forcing statutory scheme and the goals of the Clean Water Act. EPA intends to publish the proposed rulemaking for public comment in the fall of 2022. On September 18, 2017, the 120-day administrative stay was lifted postponing certain compliance deadlines. The earliest date for compliance with SEEG was November 1, 2020.

On August 31, 2020, USEPA finalized a rule revising the regulations for the Steam Electric Power Generating category (40 CFR Part 423). The rule revises requirements for two specific waste streams produced by steam electric power plants: FGD wastewater and BA transport water. In the revised rule, USEPA delays the compliance deadlines for BA transport water and FGD wastewater two years to December 31, 2025. In addition, the revised rule includes a voluntary incentive program that provides additional time, until December 31, 2028, for facilities that implement additional processes that achieve more stringent limitations and also has an allowance that electric generating units that decommission by December 31, 2028 need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities.

State Rules and Laws:
The majority of Michigan’s environmental regulations/laws/acts were consolidated into the Natural Resources and Environmental Protection Act (NREPA) of 1994, Public Act 451 as amended (Act 451). Act 451 is organized into sections called “Parts” and serves “to protect the environment and natural resources of the state; to codify, revise, consolidate, and classify laws relating to the environment and natural resources of the state; to regulate the discharge of certain substances into the environment; to regulate the use of certain lands, waters, and other natural resources of the state; to protect the people's right to hunt and fish; to prescribe the powers and duties of certain state and local agencies and officials; to provide for certain charges, fees, assessments, and donations; to provide certain appropriations; to prescribe penalties and provide remedies; and to repeal acts and parts of acts.”

Michigan Mercury Rule – The purpose of the Michigan Mercury Rule (MMR) is to regulatethe 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 CCR as a solid waste. It requires any CCR that will remain in place in asurface impoundment or landfill be subject to siting criteria, permitting and licensing of the disposal area, construction standards for the disposal area, groundwater monitoring, correctiveaction, and financial assurance and post-closure care for a 30-year period. The disposal facilityis required to maintain the financial assurance to conduct groundwater monitoring throughout the post-closure care 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 InfrastructureImprovements 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. Under the amendment, 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. ~~In 2018, Part 115 was amended to include the majority of the RCRA regulations would be enforced by states and the CCR units would not be subject to the dual regulatory structure.~~ In 2018, Part 115 was amended to include the majority of the RCRA rule, including the regulation of CCR surface impoundments used for

Commented [A1]: DTE comment: Recommend deleting

storage. Michigan's request for state program approval is currently under review by the USEPA.

To comply with PA 341 Section 6t (5) (m)
"How the utility will comply with all applicable state and federal environmental regulations, lawsand 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 ofcompliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's 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 theMichigan 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.

VI. 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 reservemargins 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 intolocal resource zones (Zones) with the majority of the Lower Peninsula in Zone 7 and the UpperPeninsula combined with a large portion of Wisconsin in Zone 2, as shown in Appendix B. Theunshaded 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.[9] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins 2022 through 2031" for the entire footprint.[10] MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report.[11] 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 the LOLE requirement while fully using the Capacity Import Limit for such."[12] The Local ClearingRequirement for each zone is reported annually with the MISO planning resource auction resultsin April.[13]

For the southwest corner of the Lower Peninsula, in PJM's territory,[14] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[15] PJM outlines requirements for an Installed Reserve Margin, similar to MISO's planning reserve margin on aninstalled capacity basis, and a Forecast Pool Requirement on an unforced capacity basis, similarto MISO's planning reserve margin on an unforced capacity basis. PJM also specifies 27 LocalDeliverability Areas somewhat similar to MISO's local resource zones.

[9] MISO 2022-2023 Loss of Load Expectation Study Report published on November 1, 2021

https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[10] 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.

[11] 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.

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

[13] MISO Planning Resource Auction results, April 2021

https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

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

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

PJM publishes a Reserve Requirement Study [16] annually in October containing the requirements for generator owners andload 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 capacitydemonstration 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 through2021. 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, toestablish 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 utilityIRP filings should be consistent with the requirements of the State Reliability Mechanism underSection 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiated to implement these provisions.

VII. 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, twomodeling scenarios are required. Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other

[16] PJM Reserve Requirement Study, October 2021.
https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx

jurisdictions. Due to the provisions in PA 341Section 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

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario directionally aligns with MISO's December 2021 Futures Report, Future 1 and reflects substantial achievement of state and utility announcements including generation retirements and environmental goals. This scenario incorporates 100% of utility integrated resource plan (IRP) retirement announcements and retirement assumptions throughout the MISO footprint, as identified in MISO Future 1. For the utility performing the analysis, the generation unit retirement assumptions may vary for only the generation units the utility has decision making authority. As subsequent MISO Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 1 of the December 2021 report may be used. This scenario assumes that CO2 emissions decline, driven by state goals and utility plans throughout the MISO footprint creating at least a 63% carbon reduction by 2040 from the baseline year of 2005 for the MISO region. This trajectory of carbon reduction is expected to continue beyond 2040.

This scenario assumes that demand and energy growth are driven by existing economic factors, with moderate electric vehicle (EV) adoption and customer electrification, resulting in moderate MISO footprint wide demand and energy growth rates. Utilities should use the most recent United States Energy Information Administration (EIA) Annual

Energy Outlook (AEO) Reference Case[17] or other reputable source for forecasted EV adoption rates. If the utility does not use EIA AEO then the EV forecast information must be provided within the utility IRP filing. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change, [18] electrification, demand side resources (if considered a demand side resource), and customer owned distributed generation and how these factors change overall load and demand.

Commented [A2]: DTE comment: See comment below

Commented [A3]: DTE comment – clarify DR which could be a demand or supply side resource

*Note: Scenario aligns with MISO Future 1 from the December 2021 MISO Futures Report. If, in the future, MISO Futures significantly change, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 1.

- Natural gas prices utilized are consistent with the Reference Case projections from the United States Energy Information Administration's (EIA) most recent Annual Energy Outlook.[19]
- Moderate EV adoption and customer electrification result in moderate footprint-wide demand and energy growth. Within Michigan, EV and electrification forecasts should be blended with historical sales such that after 3 years, Michigan's load and demand increase reflects the source forecasts for EV and electrification technologies. Load profiles of EVs and electrification technologies should be clearly delineated and presented individually such that it is clear how they each impacted the overall energy and demand forecast. EV forecasts should be based off the Reference Case in the most recent EIA AEO or other reputable source for

Commented [A4]: DTE comment – added to align with paragraph above (see comment)

[17] Electric Vehicle adoption as forecasted in the most recent EIA AEO East North Central Census Region Reference Case, http://www.eia.gov/outlooks/aeo/tables_ref.php

[18] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[19] 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 include delivery costs from Henry Hub to the point of delivery.

forecasted EV adoption rates. Electrification technology forecasts should be based off of either established proprietary forecasts or publicly available data.

- Resource assumptions: Assume MISO Future 1 retirements for existing thermal and nuclear generation resources published in the most recent Futures Report should be used when available along with recent public announcements. Specific new units will be modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON), IRP cost pre-approval, or signed generator interconnection agreement (GIA). Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO) should also be used. Generic new resources are assumed consistent with the scenario description, considering anticipated new resources currently in generation interconnection queue, and should be chosen based upon economics.
- 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 participating in the State EWR Program, 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.[20]
- Existing renewable energy and storage production tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- All storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist.[21]
- Technology costs for thermal units and wind track with mid-range industry expectations.

Commented [A5]: DTE comment – "All" is very broad. Suggest adding short and long duration storage resources or removing "all" from the sentence

[20] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)

[21] Staff Report in Case No. U-20633 issued, May 27, 2021 and adopted by the Commission in its September 24, 2021 order.

- Technology costs and limits to the total resource amount available for EWR and demandresponse programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Technology costs for solar, storage, and other emerging technologies decline with commercial experience consistent with NREL or other publicly available reputable sources.
- Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Scenario #1 Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections at the end of the study period.[22]

2. Load projections
   (a) High load growth: For the filing utility's load obligation, increase the energy and demand growth rates by at least a factor of two above the base case energy or 0.5% (whichever is larger) and demand growth rates on a per customer basis. For the region included in the scenario utilize load growth that is consistent with the most recent MISO futures.
   (b) Low load growth: EV adoption and electrification are slower than expected. Demand and load growth are consistent with 5-year historical growth rates prior to 2020 and the onset of COVID-19.

Commented [A6]: DTE comment: Recommend deleting because energy and demand do not necessarily grow at the same pace (i.e. if all EV charging occurred at night, sales would increase but demand would not change)

Commented [A7]: DTE comment: recommend deleting...it's not clear what this is referring to

[22] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.

(c) 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 the demonstration year of the utility's next capacity demonstration filing. Assume that load is returned in two phases with the first half returning halfway through the 4-year forward demonstration period and the remainder returning in the demonstration year of the utility's next capacity demonstration filing. This sensitivity does not apply to utilities within an RTO that requires the incumbent utility to show capacity for choice load.

3. If the utility is not already achieving 2% EWR, ramp up the utility's EWR savings to at least 2.0% of prior year sales over the course of 3 years within the utility's Michigan jurisdiction. EWR savings remain at 2% throughout the 20-year study period.

Scenario #2

Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario aligns with the ~~Miso's~~ MISO's December 2021 Futures Report, Future 3. It incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met. This scenario incorporates the retirement announcements and assumptions throughout the MISO footprint, as identified in Future 3. As subsequent Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 3 of December 2021 Futures Report may be used. Market energy purchases are modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3.

Commented [A8]: DTE comment: wording

Commented [A9]: DTE Comment: Recommend striking this sentence. Each utility should use the carbon intensity from their modeling of Scenario 2, based on MISO Future 3 for consistency purposes. This may vary from the averages identified in MISO Future 3.

This scenario assumes significant advancements toward electrification that drives a total energy and demand annual growth rates to 1.71% and 1.41% respectively throughout the Eastern Interconnect. Emissions decline, driven by state goals and utility plans throughout the MISO footprint, creating at least an 80% carbon reduction by 2040 from the baseline year of 2025 for the MISO region. For utilities operating in PJM, assume 80% carbon reduction by 2040 from the baseline year of 2005 for the PJM region. This trajectory of carbon reduction is expected to continue beyond 2040. Utilities should assume EV

Commented [A10]: DTE Comment – update to 2005 adoption reaches 50% of total vehicle sales by 2030 with a continuing trend toward 100% of vehicle sales continues throughout the study period. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change,[23] electrification, demand side resources (excluding demand response), and customer owned distributed generation and how these factors ~~change~~ impact overall load and demand.

- Natural gas prices utilized are consistent with Reference Case projections from the United States energy Information Administration's (EIA) most recent annual Energy Outlook.[24]
- Current demand response, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they were economically selected by the model to help comply with the specified carbon reductions in this scenario.
- EV adoption and customer electrification cause adjustments in overall load profiles as electrification and EV's are adopted through the planning horizon consistent with the most recent MISO Future 3.
- Specific new units are modeled if under construction or with regulatory approval (i.e., IRP cost pre-approval, CON, or signed GIA).
- For electric utilities independently administering their own EWR program, maintain a 2% EWR savings. If the utility is not already at 2%, ramp up the utility's EWR savings to at least 2.0% of prior year sales over the course of 3 years, using EWR cost supply curves provided in the 2021 supplemental potential study for more aggressive potential.[25] EWR savings remain at 2% throughout the study period.

Commented [A11]: DTE Comment- since utilities may model demand side resources as supply side resources, recommend striking "demand side resources" from here.

Commented [A12]: DTE Comment - see suggested changes; " the word change" implies this is being compared to something

Commented [A13]: DTE Comment - Depending on the modeling methods used by the utilities, demand side resources may not directly reduce carbon. Recommend ending sentence after "...selected by the model." and striking the rest.

Commented [A14]: DTE comment – with the significant adoption assumptions the expectation is the loadshape would change significantly. To model this MISO would need provide the loadshape assumptions or loadshape assumptions should be agreed upon and consistently applied across utilities. DTE suggests allowing each utility to determine an aggressive load forecast specific to its service territory

Commented [A15]: DTE comment: remove "consistent with the most recent MISO Future 3"; We have not seen where MISO Futures 3 has a stated position on load profiles changing over time.

Commented [A16]: DTE comment – This is an extremely aggressive assumption. It's unclear what the basis is used to determine the amounts assumed in this case and how those would be allocated to each utility's service territory. What is the intent of using this assumption in the scenario?

Commented [A17]: DTE Comment - This should be for units in the Utility's Zone only. e.g. MISO zone 7 for DTE. Renewables approved in REP or VGP cases should be added to the list.

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[23] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[24] 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.

[25] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)

- Achieve and maintain a 50% renewable energy portfolio by 2030 and another 10% from other renewable resources such as voluntary green pricing and distributed generation.
- Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- All storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist. Allow for multiple market revenue streams where applicable.
- Technology costs for wind, solar, storage and other renewables decline linearly with commercial experience and forecasted at levels resulting in a 30% reduction from Scenario 1 by the end of the 20-year study period.
- Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Existing PURPA contracts are assumed to be renewed. Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Commented [A18]: DTE Comment: This is an extremely aggressive assumption and likely unfeasible operationally to meet. This is not consistent with MISO Future 3 and should be removed.

This may have come from the MI Healthy Climate Plan, but it should not be applied to MISO Future 3, because it changes MISO Future 3 drastically away the other Future 3 specifications to meet this RPS.

Commented [A19]: DTE comment: see comment above

Scenario #2 Sensitivities:

1. Fuel cost projections: Increase the natural gas fuel price projections from the base projections to at leastthe high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections at the end of the study period. [26]
2. Assume all coal facilities in Michigan are retired by 2030 and Michigan electric sector meets an 80% carbon reduction from the 2005 baseline, modeled as a hard cap on the amount of carbon emissions.[27]
3. Remove the assumed RPS and assume that 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).
4. For electric utilities independently administering its own EWR program, ramp up to 2.5% EWR savings based upon prior year sales within the utility's Michigan jurisdiction.

Commented [A20]: DTE comment: request clarification if this is only referring to the 50% RPS noted above or also includes the incremental 10% from other renewable resources. Suggest stating exactly what is being requested

[26] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.

[27] Based upon ramping to a net zero carbon power sector by 2035 https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

VIII. Michigan IRP Modeling Input Assumptions and Sources

The following IRP modeling input assumptions and sources are recommended to be used inconjunction 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 ifapplicable. 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 scenarioand/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 • Retirement assumptions throughout the MISO footprint are consistent with MISO futures development Future 1 and Future 3.
6 - Natural Gas Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity 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/orsensitivity 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 andmade available to all intervening parties.
8 - Fuel Oil Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity descriptions.	• If utility-specific data is utilized, it should be justified andmade available to all intervening parties.
9 - Energy Waste Reduction Savings MWhs	Base Case: • 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 annualincremental savings (1.0%) as a net to load. • Not less than 35% of the state's electric needs should bemet through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3). EWR Base Case Sensitivities: • For savings beyond mandate, incorporate EWR as anoptimized generation resource. Emerging Technologies Scenario: • Ramp up EWR savings at least 2.0% over the course of four years, using EWR Cost Supply Curves provided in the ~~2017~~ 2021 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 • 2021 Energy Waste Reduction Potential Study

Commented [A21]: DTE comment: Updated to align with source material – 2021 Energy Waste Reduction Potential Study or most recent

10 - Energy Waste Reduction Costs nominal dollars per kWh (Program administrator costs only; participant costs are not to beincluded in this analysis.)	• Current average levelized costs as defined in ~~2016/2017~~2021 Energy Waste Potential Stud~~yies~~ and Supplemental Modeling reflecting aggressive and cost-effective program savings goals.	• 2021 Energy Waste Reduction Potential Study
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 demandresponse as applicable to the scenario.	• As defined by 2021 Demand Response Potential Study
12 - Demand Response Costs nominal dollars per MW	• Costs/MW by program including all payments, credits, orshared savings awarded to the utility through regulatory incentive mechanism.	• As defined by 2021 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 kWhand 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, mustbe justified and made available to all intervening parties.
15 – Other Resources	• Changes to operation guides • Options which improve reliability (Storage, SVC, HVDC, CVR) • 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, other 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 tothose technologies' and options' presently unconventionalnature. 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. • Storage Resource information
16 - Wholesale Electric Prices		• Documentation for wholesale price forecast must beprovided to all intervening parties.
17 – Electric Vehicle Forecasts	Scenario 1 EIA AEO Reference Case Scenario 2 half of vehicle sales are electric by 2030	• EIA AEO Transportation

Commented [A22]: DTE Comment: Updated to align with source material – 2021 Energy Waste Reduction Potential Study or most recent

Commented [A23]: DTE comment: Will additional information be added here?

IX. 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 as specified in the Michigan Integrated Plan Filing Requirements.
5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled overthe 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 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 goalof 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 Scenario 1 and Scenario 2, the utilities shall consider and prescreen all 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. To the extent that the utility is proposing early retirement of a generation facility (retirement that results in an undepreciated plant balance and prior to the end of the assumed useful life), the utility should present an NPVRR analysis that compares various financing options.

15. Recognize capacity and performance characteristics of variable resources.
16. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.
17. Take into consideration existing power purchase agreements, green pricing and/or other programs.
18. 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. The utility should explicitly identify revenues that are expected to be earn that are offsets to the net present value of revenue requirements and the assumptions that those revenues are based upon.
19. An analysis regarding how incremental investments would compare to large investments in specific technologies that might be obsolete in a few years.

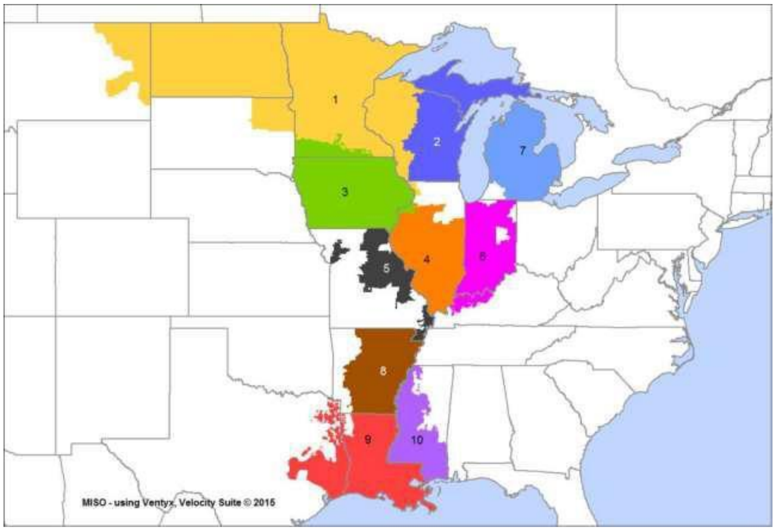
Commented [A24]: DTE Comment: This should be limited to new resources being considered, revenues from units being considered for retirement, and revenues from existing assets that would significantly change depending on the resulting build plan only. Quantifying any and all revenues expected to be earned by the utilities assets is overly burdensome for an IRP, may be difficult to forecast, or not impact the optimization results because they cancel out in a delta analysis.

Commented [A25]: DTE comments: What technologies are expected to be obsolete in a few years? This should be more specific

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

Update with Phase II and Phase III participants

Appendix B: Map of MISO Local Resource Zones



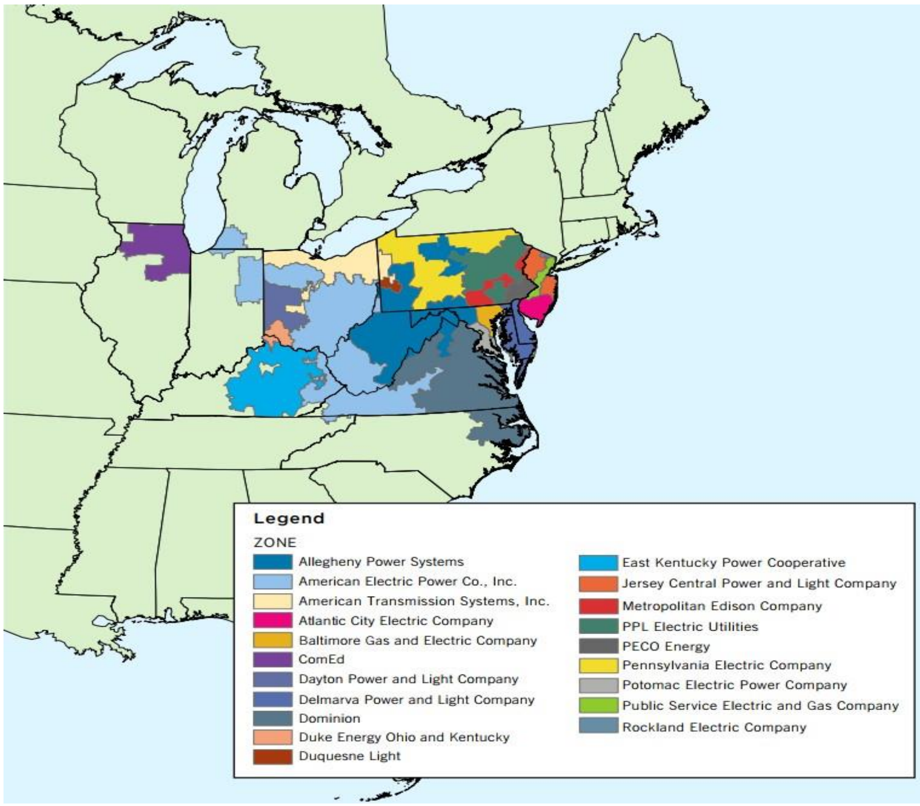
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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

MISO Zone 7 - Rate regulated electric utilities - Alpena Power Company, Consumers EnergyCompany, 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 ispart 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 the following as part of the proceeding:

(a) Conduct an assessment of the potential for energy waste reduction in this state, based on whatis 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 whatis economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already beeninstalled in this state and seek to fully maximize potential benefits to ratepayers in lowering utilitybills.

(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 additionto 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 foradditional 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 includein developing its integrated resource plan, receive written comments and hold hearings to solicitpublic input regarding the proposed modeling scenarios and assumptions.

Appendix E: Environmental Regulatory Timeline

- Updated chart forthcoming.

Integrated Resource Plan

Filing Requirements

Pursuant to Public Act 341 of 2016, Section 6t

Application Instructions for Integrated Resource Plan Filings

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

Schedule

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

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

Filing Announcement

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

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

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

The filing announcement shall include:

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

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

Pre-Filing Request for Proposals

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

a) The utility shall include with the IRP application documentation demonstrating that the RFP process was completed.
b) The utility's RFP process is subject to audit by the Staff.
c) The IRP filing shall include evidence that the pre-filing RFP process was conducted in a manner consistent with the competitive procurement guidance in Case No. U-20852, the Commission's code of conduct, and applicable state, federal, and Commission rules.
d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, pursuant to MCL 460.6t(6).

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

Stakeholder Engagement and Public Outreach Process

Participant engagement early in the development of the IRP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decision-making process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.

In the 12 months prior to the IRP filing, each utility is encouraged to host update workshops with interested participants. The purpose of the pre-filing workshop(s) is to ensure that participants have the opportunity to provide input and stay informed regarding: (1) the assumptions, scenarios, and sensitivities; (2) the progress of the utility's IRP process; and (3) plans for the implementation of the proposed IRP. Documentation demonstrating the public outreach process undertaken by the utility shall be included with the IRP filing. Documentation may include:

a) Workshop dates and times, including times outside of the workday.
b) Evidence that a notice of the workshops was provided to the public.
c) Meeting minutes.
d) Meeting or workshop attendance lists.
e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application; and
f) Discussion indicating if or how the public outreach process influenced the IRP.
g) Include descriptions of community outreach efforts for vulnerable communities in the Company's service territory. Vulnerable communities should be identified using the MI EJ Screening Tool or other tools as noted in the Section XVIII.

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

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

If the utility chooses to hold pre-filing workshops, including stakeholder engagement workshops or public meetings, the utility shall prepare a public outreach report to document the outcomes of any pre-filing workshops, and shall file the report with the IRP application.

All presentations, recordings, comments, and transcripts should be maintained on a website in a location open to the public for the duration of the stakeholder outreach process and the duration of the IRP case, until a final commission order is published.

Risk Assessment Methodology

The utility's IRP filing shall include a thorough risk analysis of the proposed resource plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the proposed resource plan and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies and the PCA for each scenario to determine how each strategy would perform in an unexpected range of possible futures. The risk assessment methodology should incorporate the potential impacts of climate change in the forecasts for input variables.[1,2] Utilities are

Commented [A1]: DTE comment - This is overly broad. Should be reworded to "as well as alternative build plans considered by the utility."

Commented [A2]: DTE comment - There is no PCA for each scenario - there is one PCA - which may or may not match the optimal build plan from one of the scenarios. Our understanding is that utilities are not to propose multiple pathways, rather one singular PCA. Suggest rewording to "optimal build plan for each scenario" or "least cost build plan from each scenario."

[1] https://glisa.umich.edu/summary-climate-information/
[2] https://ccr.nelson.wisc.edu/

encouraged to link variables that are correlated to or dependent upon one another. The IRP shall include a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent- based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.

Confidential Information

Transparency and the use of data that can be shared with the Commission, the Staff, and intervenors is encouraged. Proprietary, confidential, and other nonpublic materials used in the development of the forecasts, scenarios, or other aspects of the IRP shall be presented in such a way that the proprietary and confidential nature of the materials is preserved. The use of publicly available data and materials is encouraged in lieu of proprietary and confidential materials and claims that information is proprietary or confidential should be justified by the utility.

Inclusion of specific materials in the IRP filing may be contingent upon appropriate confidentiality agreements and protective orders. Proprietary, confidential, and other nonpublic materials filed as part of the IRP shall be clearly designated by the utility as confidential.

Definitions

The following definitions are provided to aid in ensuring consistency across planning processes.

Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system.

Non-Wires Alternatives - An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.

Vulnerable, Disadvantaged, Underserved Communities – to be defined in coordination with EGLE. See Appendix (IV) below.

Demand-side Resources - Resources ~~serve~~ serving resource adequacy needs by reducing or shifting load, which reduces the need for additional generation including but

Commented [A3]: DTE comment – proposed additional language not limited to EWR, DR, grid and software controls, Behind the meter resources, distribution connected storage, etc.

Co-Benefits – Benefits that are quantified as part of another planning or an evaluation process that are important to the justification of a resource included in the integrated resource plan. Examples include benefits to distribution planning or evaluation of multiple revenue streams.

Approval of Costs

For the Commission to specify the costs to be approved for the construction of or significant investment in supply or demand-side resources, or contractual agreements, excluding short-term market capacity purchases to meet state reliability mechanism capacity requirements, in accordance with MCL 460.6t(11) through (12), the following information, data, and documents shall be provided:

I) For specific supply-side resources (inclusive of storage technologies) of less than 225 megawatts (MW) (this threshold shall be applied to the nameplate capacity of a project, not individual generators, storage facilities, etc.), that are planned to go into service within three years following the approval of the IRP, the following evidence (covering the lifespan of the project) shall be ~~provided:~~ provided:

   a) A description of the plant size, type, and summary of engineering/design specifications. The description shall also include the following:
      i. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
      ii. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and
      iii. Annual depreciation on the capital investment.
   b) Projected annual return and income taxes on capital investment.
   c) The operation and maintenance (O&M) costs over the life of the facility described as costs which are variable, in current dollars per kilowatt-hour (kWh), with expenses for fuel and non-fuel items indicated separately; and costs which are fixed, in current dollars per kilowatt.
   d) Projected property taxes.

Commented [A4]: DTE comment: duplicative

e) The rates of escalation of cost, including:
    i. Capital costs.
    ii. O&M costs which are variable and related to fuel.
    iii. O&M costs which are variable and unrelated to fuel.
    iv. O&M costs which are fixed.
f) The total annual average cost per kWh at projected loads in current dollars for each year of the plan for the proposed facility.
g) Equivalent availability factors, including both scheduled and forced outage rates.
h) Capacity factors for each year in the planning period.
i) Operation cycle (i.e., baseload, intermediate, or peaking), identifying expected hours per year of operation, number of starts per year, and cycling conditions for each year in the planning period.
j) Heat rates (efficiency) for various levels of operation.
k) Unit lifetime, both for accounting book purposes and engineering design purposes, with explanations of differences.
l) Lead time, separately identifying the estimated time required for engineering, permitting and licensing, design, construction and pre-commercial operation date testing.
m) Potential socioeconomic impacts, such as employment, for the local region of the proposed supply-side resource, construction of or significant investment in an electric generation facility, or the purchase of an existing electric generation facility.
n) Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.

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

Commented [A5]: DTE Comment - Does incremental refer to just renewable build outside of the REP? Any assets in REP have Rev Req and ICOC consistent with this method.

a) Capital, operating and maintenance costs for renewable energy systems (including property taxes and insurance for renewable energy systems).

b) Financing costs.
c) Costs that are not otherwise recoverable in base rates including interconnection and substation costs.
d) Ancillary service costs.
e) Cost of purchased renewable energy credits (RECs) other than those purchased for non-compliance.
f) Cost of Contracts.
g) Expenses incurred as a result of governmental action including changes in tax or other laws.
h) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029.
i) Recovery to include the authorized rate of return on equity, which will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved (only through 2029).
j) Provide the following information in relation to renewable resource cost recovery:
    i. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and
    ii. Forecast through the end of the renewable plan period of the regulatory liability balance.
k) Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.
l) A description of the decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling for proposed new renewable resources.

III) Energy Waste Reduction: The utility shall providethe following information in relation to energywaste reduction programs cost approval and recovery. For each individual program or group of programs,provide:

a) Total annual cost including:
    i. Annual O&M cost for each individual portfolio of energy waste reduction programs.
    ii. Annual capital cost for each individual portfolio of energy waste

Commented [A6]: DTE comment – what is meant by ancillary service costs? Is this referring to integration costs, the MISO definition of Ancillary Services: Those services that are necessary to support Capacity and the transmission of Energy from Resources to Loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice, or reactive power credits, or something else?

reduction.

iii. Expected cost-sharing or financial incentive granted to the utility by the Commission.

b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable.

c) Maximum single event demand reduction.

d) Total resource capacity (MW) and type reported to theapplicable regional transmission organization (RTO)/independent system operator (ISO).

e) Total energy reduction achieved in megawatt-hours (MWh).

f) Description of program, including customer enrollment, technology used, and marketing plan.

IV) Demand Response and DER Programs:

The utility shall provide the following information in relation to demand response programs and DER programs cost approval and recovery. For each individual program or group of programs, provide:

a) Total annual cost including:

i. Annual O&M cost for ~~each individual program of~~ demand response at the portfolio level and DER programs.

ii. Annual capital cost for each individual program of demand response and DER programs.

iii. Expected cost-sharing or financial incentive granted to the utility by the Commission.

b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable.

c) Maximum single event demand reduction.

d) Total resource capacity (MW) and type (load modifying resource, emergency demand response, etc.) reported to the applicable regional transmission organization (RTO)/independent system operator (ISO).

e) Total energy reduction achieved (megawatt-hours (MWh)); and

f) Description of program, including customer enrollment, technology used, and marketing plan.

Commented [A7]: DTE comment: Recommend removing "customer enrollment" and marketing plan". Marketing plans and customer enrollment strategies are addressed in EWR Plan filings. EWR in an IRP is modeled at the end-use level based on the most recent potential study, not at the program level. For example, DTE has over 25 EWR programs, each of which requires a separate marketing plan and enrollment strategy.

Commented [A8]: DTE comment: propose only including capital in item a below. Per U-18369, only capital is approved in the IRP. From the order: "actual capital spending in the examination period will be reconciled against the amount approved in the IRP and recovered in the rate case, while O&M spending will be reconciled against the amount both approved and recovered in the general rate case."

Commented [A9]: DTE comment: See comment above. If kept update to the portfolio level

Waivers and Process for Smaller and Multistate Utilities

An electric utility with fewer than 1,000,000 customers in this state may request a waiver to any portion of these IRP filing requirements. Any request for a waiver shall include a discussion and justification outlining why the waiver is warranted and in the best interest of its customers. Discussion and justification for the requested waiver shall include a description of the utility's current and forecasted energy and capacity needs, and its plan for meeting those needs over the upcoming ten years.

If the utility requires resolution of a waiver request prior to filing an IRP application, the utility shall file the waiver request no less than 60 days prior to the filing of the IRP application.

An electric utility with fewer than 1,000,000 customers in this state may request approval from the Commission to file an IRP jointly with other smaller utilities. Commission approval is required prior to filing a joint IRP.

A non-multistate Michigan electric utility serving fewer than 1,000,000 customers may elect to file an IRP, based on its specific circumstances, that deviates from these requirements, but that is subject to the Staff's ability to request supplemental information. The filing shall include an explanation of why the deviations are reasonable under its circumstances. The Commission shall review any such filings under the traditional "just and reasonable" standard.

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

IRP Filing, Data, and Documentation

The utility's IRP filing shall demonstrate compliance with MCL 460.6t and include the following items:

a) Letter of transmittal expressing commitment to the approved resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisitionstrategy, acknowledging that the utility reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.

b) Technical volume(s) that fully describe and document the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy.
c) The data and information requested in the Commission's IRP filing requirements included herein; and
d) Any other information deemed relevant by the utility.

The utility's IRP filing shall include an IRP document(s) and application information including testimony and exhibits that fully describes and documents the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy. To facilitate a similar format for each utility's application, the utility is encouraged to align its filing with this provided outline and include at least the following items:

I) Executive Summary:

An IRP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The executive summary shall be an informative non-technical description of the resource plan proposed by the utility and resource acquisition strategy.The executive summary shall summarize the contents of the IRP documentand shall include the following:

a) An overview of the planning period examined in the IRP analysis and application.
b) A brief introduction describing the utility, its existing facilities, new resources being proposed, and implementation strategy.
c) A summary of the state, federal, ISO, RTO resource adequacy regulations applicable to the utility.
d) A summary of the analytical approach used in the utility's analysis and the types of new resources considered.
e) A description of how the analytical approach considered potential resource co-benefits from other planning processes such as distribution or transmission planning.

f) A summary of any retirement analysis performed.

g) A description of how the environmental justice analysis results influenced the utility's proposed course of action.

h) The Company shall include a graph that depicts a stacked bar graph that includes the RTO capacity credit[3] of all existing resources and PCA resource additions, color designated by resource type, that it will use to serve demand in each year for all planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin.

i) The Company shall include graph that depicts a stacked bar graph that includes the annual energy expected to be produced by all existing resources, PCA resource additions, and market purchases for each year of the planning horizon. The graph shall be color designated by resource type. The graph shall have a line representing expected demand over the length of the planning period.

j) The Company shall include graph that summarizes the total of each of the following pollutants projected using the PCA in the MIRPP Scenario 1 for each year of the planning horizon. A graph should be included for NOx, So2, CO, PM, Pb, Hg, VOC, CO2. The graph should also depict the utility's progress toward or achievement of State, Federal and utility announced goals or requirements by including annotations for those goals on the years they apply.

k) Any other information that would aid the public understanding of the utility's proposed resource plan.

II) Table of Filing Requirements.

The utility shall provide a table that clearly identifies the where in the filing it has met all of the filing requirements. It shall include locations in testimony, exhibits and workpapers.

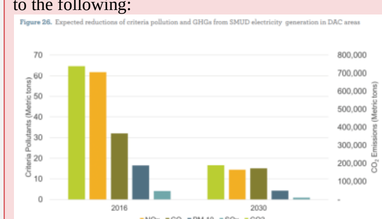
III) Testimony Introduction:

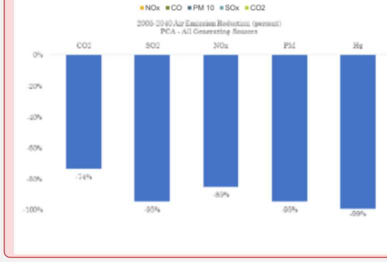
The utility shall describe resource plans to satisfy at least the objectives and priorities identified in MCL 460.6t. The utility may identify and/or

[3] For example, MISO Zonal Resource Credit.

Commented [A10]: DTE comment: This is overly broad, burdensome and too much information to include in a graph. Recommendation to present a range of intervals (from base line through study year) or a decrease during the study period for the following emissions CO2, SO2, NOx, PM, Hg

Commented [A11R10]: Propose doing something similar to the following:





describe additional planning objectives that the resource plan will be designed to meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that consider the planning objectives and priorities. The introduction shall include the following:

a) General description of the utility's existing energy system, including:
    i. Net present value of utility revenue requirements,[2][4] with and without any financial performance incentives for demand-side resources.
    ii. Incremental ~~R~~revenue requirement of existing generation and power purchase agreements.
    iii. Summary of existing generation and power purchase agreements by fuel type.
    iv. Utility's existing capacity resource mix.
    v. Utility's service territory and breakdown of customer class composition; and
    vi. Description of planning period analyzed.
b) Statement of power need.
c) Identify and explain the basis for the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements, for each year of the analysis used in each scenario and sensitivity evaluated by the utility as part of the IRP process.
d) Market and regulatory environment influencing resource planning decisions:
    i. RTO market and state regulation structure if a multistate utility.
    ii. Potential changes to RTO capacity market.
    iii. Electric customer choice.
    iv. Transmission expansion.
    v. Environmental.
    vi. Renewable portfolio standards; and
    vii. Other.
e) IRP planning process; and
f) Stakeholder report.

IV) Analytical Approach:

Commented [A12]: DTE comment: Added incremental for clarity here and in other instances. The Revenue Requirement reported by the capacity expansion model is typically an incremental rev req and does not include the full rev req on existing assets.

[4] [2]The assumed discount rate shall be included along with a justification for the assumed discount rate. Resultsshould be presented in nominal dollars

a) Describe the modeling process, including the duration of the study;

b) The utility shall describe and identify how its model approach optimizes resources to meet load and demand for all times of the year and for each year of the planning horizons. The utility shall explain how the model considers the seasonal and operational characteristics of all resource types, including monthly generation profiles, forced outages, derates, seasonal or limited availability of resources, etc.

c) Describe and provide a justification for the risk analysis approach adopted from the Risk Assessment Methodology section:

   i. The utility shall describe and document its quantification of the risk that affects the evaluation of the various resourceplan options.

   ii. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings affected its decision on a resource plan.

   iii. If multiple forms of risk assessment are presented the utility shall explain why certain risk variables could not be included in or are unsuited for one type of risk assessment or another. Considering a risk variable under multiple forms of risk assessment is not discouraged.

d) The utility shall describe and document the identification of risk variables and/or combinations of risk variables selected, their ranges, probabilities, ranking, and/or weighting that defines the risk quantification which the various resource plan options were judged; describe how these risk variables were judged to be appropriate and explain how these were determined; and describe themodeling tools and data sources employed during the capacity expansion, and other modeling processes.

e) Interactions between risk variables should be captured to the extent that it is practical. Evaluation of variables in isolation is acceptable so long as there exists a comprehensive evaluation of resource plans risks that captures interactions and shows overall risk of appropriate build plans. A comprehensive risk assessment should at least include optimized build plans from the required MIRPP scenarios for the proposed resource plan and any alternative resource plans presented by the utility.

Commented [A13]: DTE comment – it is unclear what this means as written (the "for"). Should it say "A comprehensive risk assessment should at least include optimized build plans from the required MIRPP scenarios, the proposed resource plan. and any alternative resource plans presented by the utility."?

V) Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities.
b) In addition to the utility's own scenarios and assumptions, the inclusion of the established modeling scenarios and assumptions in the MIRPP approved by the Commission in Case No. U-21219, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.

VI) Existing Supply-Side (Generation) Resources:

Detailed account of projected energy and capacity purchased or produced by the utility's owned and contracted resources, including cogeneration resources. Include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:

a) Overview.
b) Fossil-fueled generating units.
c) Nuclear generating units.
d) Hydroelectric generating units.
e) Renewable generating units.
f) Energy storage facilities.
g) Power purchase agreements: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource.
h) RTO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating costs, etc.).
i) Spot market purchases and off-system sales.

VII) Demand-Side Resources:

Historical and projected load management and demand response programs for the utility in terms of MW and Midcontinent Independent System Operator, Inc., Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and demand response events for each program. The following items are to be included:
    i. Description of current demand response and load management programs for the IRP study horizon, including the amount of

load reductions and the expected hours of interruption per day, month, and year for each program.

ii. Review the historic performance of existing demand-side programs in delivering benefits and how the utility used such information in its demand response resource decisions.

iii. Describe the utility's method for determining whether to purchase energy rather than relying on demand response.

iv. A description of any other programs the utility is considering that could potentially expand demand response resources, including expected load reductions and operating parameters.

VIII) Renewables and Renewable Portfolio Standards Goals:

Projected energy purchased or produced by the utility from renewable energy resources.

a) Describe how the electric provider will meet existing renewable energy standards. If the level of renewable energy purchased or produced is projected to drop over the planning periods, the utility must demonstrate why the reduction is in the best interest of ratepayers.
b) Specify whether the number of MWh of electricity used in the calculation of the renewable energy credit portfolio will be the previous 12-month period of weather-normalized retail sales or based on the average number of MWh of electricity sold by the electric provider annually during the previous three years to retail customers in this state.
c) Include the expected incremental cost of compliance with existing renewable energy standards for the required compliance period.
d) A description of how the electric provider's plan is consistent with the renewable energy goals required by the Michigan Legislature (e.g. 35% combined renewable energy and energy waste reduction goal by 2025);
e) Describe the options for customer-initiated renewable energy that will be offered by the electric provider and forecast sales of customer-initiated renewable energy.
f) Describe how the electric provider will meet the demand for customer-initiated renewable energy.

The following non-exhaustive list suggests several elements that may be included:

a) Sales forecast through 2021 for compliance with the renewable energy standard, through 2025 toward meeting the 35% goal, and through the study period.
b) Detailed resource plan:
    i. Describe the utility's planned renewable energy credit portfolio.
    ii. Forecast RECs obtained via Michigan incentive RECs.
    iii. Forecast expected compliance levels by year to meet the renewable portfolio targets.
    iv. Identify key assumptions used in developing these forecasts and the proposed resource portfolio.
    v. Identify risks which may drive performance to vary.

IX) Peak Demand and Energy Forecasts:

A long-term forecast of the utility's sales and peak demand under various reasonable scenarios. Include details regarding the utility's plan to eliminate energy waste, including the total amount of energy waste reduction expected to be achieved annually, and the cost of the plan:

a) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.
b) Subsections:
    i. Key variables used to develop forecast.
    ii. Long-term forecasting methodology.
    iii. Forecasting uncertainty and risks.
    iv. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers).
    v. Base Case deliveries and demand forecast.
    vi. Alternative forecast scenarios and sensitivities in accordance with the Commission's final order in Case No. U-21219, or subsequent Commission orders relating to IRP modeling parameters and requirements.

Commented [A14]: DTE comment – suggest deleting the reference to the historical period and say from the first year of the study period through 2025 demonstrating compliance with the renewable energy standard and progress toward meet the 35% goal in 2025

Commented [A15]: DTE comment: suggest deleting this part of the sentence. There are no specific peak reduction targets a utility must achieve, only sales targets that may or may not achieve peak reduction.

Commented [A16]: DTE Comment: This is overly burdensome, rather than provide in workpapers, propose providing reference to previous filings (i.e. Case numbers) with their respective forecasts to help cut down on workload

vii. ~~Include detailed information about~~Describe in detail how the forecasts used for IRP modeling align with forecasts used for distribution planning.

viii. Detail information about distributed energy resource adoption and operation.

ix. Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts.

x. Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts.

X) Capacity and Reliability Requirements:

The utility shall indicate how it complies, and will comply, with all finalized state federal, ISO, RTO capacity and reliability regulations, laws, rules and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including the projected costs/revenues of complying with those regulations, laws, and rules. The utility shall identify any finalized changes to the applicable state, federal, ISO, or RTO capacity and reliability regulations, laws, rules and requirements that have occurred since its last IRP fining, including narrative that identifies how its PCA satisfies those requirements. The utility shall include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation foreach facility in the portfolio.

XI) Transmission Analysis:

In accordance with MCL 460.6t(5)(h), the utility shall work with their local transmission owner to include an analysis ofpotential new or upgraded electric transmission options for the utility. The utility's analysis shall include the following information:

a) The utility shall work with their local transmission owner to assess the need to construct new or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options.

b) In collaboration with their incumbent transmission owner, include an analysis of any co-benefits of storage, specifically the transmission system benefits associated with transmission

Commented [A17]: DTE comment: suggested wording changes

Commented [A18]: DTE comment: This words detail information are vague.

Commented [A19]: DTE comment: request clarity on the word operation. Using the word operation could be interpreted as including FTM DERs that is not in the scope for the sales forecast. Such replacing with associated assumptions

Commented [A20]: DTE comment – please clarify what is meant electrification. What technologies does this include since EV is listed in IX?

interconnected storage that is not designated as a storage as transmission only asset.

c) A detailed description of the utility's efforts to engage local transmission owners throughout the utility's IRP process. To inform the IRP process and assumptions, a meeting schedule should be set in advance. The filing should include the pre-decided meeting schedule, any documentation that supports requested extensions of the initial pre-decided timing, and a summary of meetings that ultimately took place.

d) Detailed meeting minutes for utility/transmission owner meetings should include any requested studies, discussions about assumptions and any conclusions made during the meeting, alternatives that were reviewed, any other pertinent information that can be made public or provided through typical contested case confidentiality agreements.

e) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns.

f) Any information provided by their local transmission owner indicating theanticipated effects of fleet changes proposed in the IRP on the local resource zone's (LRZ) capacity import limit (CIL) transmission system, including both generation retirements and new generation, subject to confidentiality provisions.

Any information provided by their local transmission owner, including costand timing, indicating potential transmission options that could impactthe utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboringRTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources ordemand-side resources; (5) estimated interconnection costs for new resources (6) potential siting locations that may provide transmission system benefits.

g) In collaboration with their local transmission owner, any information

Commented [A21]: DTE Comment: The IRP is not site specific for resource additions therefore site specific transmission benefits would not be easily quantified. The transmission owner would need to provide the details on if there is a more appropriate location for a proposed future storage site

Commented [A22]: DTE comment – propose deleting this language since it is captured below in #1 or incorporated into #1 regarding (1) identification of system locations or regions where energy resources can interconnect to the transmission system with minimal transmission investment, (2) recent studies that indicate ways in which the capacity import or export capabilities can be increased or may change and the resulting impacts to the local clearing requirement.

h) Any transmission studies performed by their local transmission owner that support the resource plan proposed by the utility.

i) In conjunction with the local transmission owner, provide an analysis of transmission costs for access to out of state resources conducted by either the RTO, transmission owner(s), and/or utility.

j) Provide RTO reports or web links to report locations that contain information relied upon to support model assumptions or other IRP decisions.

XII) Fuel

The utility shall include the following:

a) Overview.
b) Natural gas price forecasts under the various scenarios.
c) Oil price forecasts under the various scenarios.
d) Coal price forecasts under the various scenarios.
e) Delivered natural gas prices to existing and new utility-owned generating plants.
f) Delivered oil prices to existing and new utility-owned generating plants.
g) Delivered coal prices to existing and new utility-owned generating plants.
h) Projected annual fuel costs under the various scenarios; and
i) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new and existing generation facility.

XIII) Resource Screen:

Describe the utility's options of resources, including combinations of resources constructed as a single facility (such as storage combined with a generation source), to serve future electric load such as utilizing existing and planned resources, build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a power purchase agreement. The following sections shall discuss each option in detail and options shall be considered in combination to serve future electric load. As described below, workpapers with information on the costs of eachresource option and combination of resource options shall be provided with the utility's filing:

a) Existing and planned resources.
b) New build:
    i. New generation technology and operating assumptions.
    ii. New generation development costs.
    iii. New energy integration of storage technology and operating assumptions; including all storage options.
    iv. New energy storage development costs.
    v. Development costs and operating assumptions for combinations of resources constructed as a single facility.
c) Distributed Energy Resources inclusive of non-wires alternatives identified in other planning processes.
d) Demand-side Resources inclusive of non-wires alternatives identified in other planning processes.
e) Market capacity purchases:
    i. Regional market supply outlook.
    ii. Availability of market capacity.
    iii. Market capacity price assumptions.
f) Long-term power purchase agreements.
g) Transmission resources:
    i. Overview.
    ii. Existing import and export capability.
    iii. Transmission network upgrade assumptions for the IRP; and
    iv. Import and export impact on resource strategy.

XIV) Modeling Results:

An analysis of the capital costs, energy production, energy production costs, fuel costs, energy served, capacity factor, emissions (levels and costs), and viability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state. The following suggest specific items to be included. They are not exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination).

b) Results for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that include annual revenue requirements, present value of annual incremental revenue requirements and incremental netpresent value of revenue requirements, and portfolio capacity including additions and retirements. Include monthly and annual energy pricing, and resource capacity and load factors.

c) Base case portfolio options to be selected from.

d) Analysis of IRP results.

e) Risk assessment presented with graphics and data that illustrate stochastic risk analysis results such that the probability distributions are clearly defined along with relative positions of the distributions so that plans can be directly compared on a single graph. The use of a box and whisker plot and/or efficient frontier plot is recommended.

Commented [A23]: DTE comment: Added incremental for clarity here and in other instances. The Revenue Requirement reported by the capacity expansion model is typically an incremental rev req and does not include the full rev req on existing assets.

Commented [A24]: DTE comment - This wording presumes that stochastic risk analysis is the type of risk analysis chosen. This is not consistent with Risk assessment methodology section above. Suggest adding, "If stochastic risk assessment is the chosen risk assessment method, then present with graphics and data......"

XV) Proposed Resource Plan

Include a detailed description of:

a) The type of generation technology proposed for a generation facility or combination of resources constructed as a single facility contained in the plan and the proposed capacity of the generation facility or combination of resources constructed as a single facility, including projected fuel costs under various reasonable scenarios.

b) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements.

c) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new generation facility; and

d) How the utility will meet local, state, and federal laws, rules, and regulations under the proposed course of action.

The utility shall describe the process used to select the proposed resource plan, including the planning principles used by the utility to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall describe how its proposed resource plan satisfies the following:

a) Strike an appropriate balance between the various planning objectives specified.
b) Utilize renewable and demand-side resources to comply with existing laws, goals and, in the judgment of the utility, are consistent withthe public interest to achieve state energy policies; and
c) In the judgment of the utility, the proposed resource plan, in conjunction with thedeployment of demand response measures, has sufficient resources toserve load forecasted for the implementation period.

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain:

a) A schedule to report the status of an approved plan in accordance with MCL 460.6t(14);
b) A schedule and description of actions to implement ongoing and planned demand-side programs and demand-side rates.
c) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction.
d) A net present value revenue requirement comparison of its proposal and reasonable alternatives over the planning period utilized in the analysis. It shall also include the calculation and comparison of the net present value revenue requirement of the utility's proposed resource plan and any alternative resource plans including the alternative resource plans resulting from theCommission-approved modeling scenarios. In addition, the utility shall provide support for its chosen discount rate and discuss how the results of its analysis would change with different discount rate assumptions.
e) A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning (such as reliability and resilience benefits) when those benefits are unable to be captured

through capacity expansion modeling runs, to the extent that the co-benefits were relied upon for justification of resource decisions.

f) A description of how, to the extent practical, the construction or investment in new resources in this state will be completed using a workforce composed of residents of this state.

g) A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state.

XVI) Rate Impact and Financial Information:

Projected year-on-year impact of the proposed resource plan (and other feasible options) for the periods covered by the plan, covering the following accounts:

a) Incremental Revenue requirement.
b) Rate base.
c) Plant-in-service capital accounts.
d) Non-fuel, fixed operations and maintenance accounts.
e) Non-fuel, variable operations and maintenance accounts.
f) Fuel accounts.
g) Emissions cost.
h) Effluent additive costs; and
i) Projected change in generation plant-in-service.

The utility shall describe the financial assumptions and models used in the plan. The resource plan shall include, at a minimum, the following financial information,together with supporting documentation and justification:

a) The general rate of inflation.
b) The allowance for funds used during construction rates used in the plan.
c) The cost of capital rates used in the plan (debt, equity, and weighted) and the assumed capital structure.
d) The discount rates used in the calculations to determine present worth.
e) The tax rates used in the plan.
f) Net present value of incremental revenue requirements for the plan.
g) Nominal incremental revenue requirements by year; and
h) Average system rates per kWh by year.

Commented [A25]: DTE comment – see above, added incremental for clarity

Commented [A26]: DTE comment – see above

Commented [A27]: DTE comment – see above

If the utility is proposing retirement of generation facilities that are expected to have an undepreciated book balance at the time of retirement, the utility shall include an analysis of various financing options for the remaining book balance if the utility is asking for specific treatment of the undepreciated book balance in its IRP. The utility shall:

a) include an analysis of various financing options for the remaining book balance.

b) identify the impact the different financing options have on the net present value revenue requirement of the proposed resource plan over the entire planning horizon.

c) provide detail to support how the financing treatment requested is the most reasonable and prudent financing means.

XVII) Environmental Considerations and Environmental Justice:

Describe how the utility's resource plan and any alternative resource plans presented in the application will comply with all applicable local,state, and federal environmental regulations, laws, and rules:

a) Include a list of all environmental regulations that are applicable to the utility fleet. Identify which regulations apply to which resources.
b) Include all capital costs for compliance with new and reasonably expected environmental regulations for existing fleet assets in the utility IRP**.**
c) Include a chart that compares the total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify its use of a carbon accounting methodology identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases.[5]
d) If the Company is proposing retirement of an existing resource, clearly identify the capital cost for environmental regulations and

Commented [A28]: DTE comment –Suggest modifying to each MIRPP base scenario (no sensitivities applied) least cost plans, the PCA, and other alternatives determined by the utility.

Commented [A29]: DTE comment – wording

Commented [A30]: DTE comment - clarify that this means future capital costs.

[5] Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases[5], https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019

other capital investments in the facility. Costs that are identified as avoided capital costs shall also be identified as avoided capital costs due to becoming cost of removal, or fully avoidable capital costs.

e) Hold a technical conference with MPSC and EGLE staff within 30 days after the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers.

f) Provide emission data to inform the Department of Environment, Great Lakes, and Energy Advisory Opinion consistent with the specifications in Appendix A.

g) Identify, quantify and provide evidence in the filing that shows progress in meeting any state, federal or utility announced carbon reduction goals. Illustrate how each optimized build plan for each MIRPP scenario, the proposed resource plan, and the previously approved plan perform in meeting those goals throughout the planning period. [6] [7]

Commented [A31]: DTE comment – too broad, suggest adding Base: "MIRPP scenario base, e.g., without sensitivities applied"

XVIII) Exhibits and Workpapers:

The filing shall include exhibits and workpapers as outlined below, subject to any license or other confidentiality restrictions that are unable to be resolved by issuance of a protective order.

a) The Company shall include an exhibit containing a table that designates where each filing requirement is included within its testimony, exhibits, and workpapers with appropriate page and section numbers.

b) The Company shall include an exhibit that depicts a stacked bar graph that includes the RTO capacity credit of all existing resources and new resources for all scenarios and sensitivities, color designated by resource type, in each of the planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin.

Commented [A32]: DTE comment: This is excessive and overly burdensome. Suggest this should be limited to the PCA and alternative resource plans. At a minimum it should be consistent with the request in c) below

c) The Company shall include an exhibit that depicts a series of

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[6] Governor Gretchen Whitmer signed Executive Directive 2020-10 (ED 2020-10) regarding the urgent threat to the environment, economy, and the health and well-being of Michigan's residents posed by climate change and its implications. ED 2020-10 committed Michigan to pursuing a reduction of at least 26 to 28 percent in Greenhouse Gas (GHG) emissions below 2005 levels by 2025 and economy-wide carbon neutrality to be achieved no later than 2050 and maintained thereafter.

[7] April 22, 2021, President Joe Biden announced carbon reduction targets for the United States building upon carbon reductions to date. The new targets call for an economy-wide net GHG reduction of 50 to 52 percent from 2005 levels by 2030 and net zero GHG emissions economy-wide by no later than 2050.

stacked bar graphs that include the energy expected to be produced by all existing resources, new resources, and market purchases for each planning year and for all MIRPP required scenarios and sensitivities. Each graph shall be color designated by resource type. Each graph shall have a line representing expected demand over the length of the planning period.

d) Include a chart that compares the total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify which of the carbon counting methodologies it used for all scenarios and sensitivities. The methodology should be one identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases.[8]

e) Any workpapers used in developing the application, supporting testimony, and IRP. Such workpapers shall, when possible, be provided in electronic format with formulas intact.

f) Any modeling input and output files used in developing the application, supporting testimony, resource plan, and any alternative plans. Such modeling input and output files shall, when possible, be provided in electronic format with formulas intact. The utility shall also identify each modeling program used and provide information for how interested parties can obtain access to such modeling program. Modeling inputs and outputs in the model-dependentbinary format should be made available to parties that obtain a license.

g) Cost data**,** estimates**,** and co-benefit analyses that were used in the resource screening process or in any other way to determine resource selection of each electric resource that was considered either individually or in combination with other resources constructed as a single facility, including distributed energy resources, storage, and renewable energy resources.

h) A description, including estimated costs of each alternative proposal

Commented [A33]: DTE comment: This description is confusing. Request clarification. What is the series of? Is the energy shown color coded by resource type on the y axis and the years on the x axis? Why are the descriptions of b and c different?

Commented [A34]: DTE comment: See comment above. This is also duplicative with requirement XVII c) above.

Commented [A35]: DTE comment: accounting?

[8] https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019.

received by the utility.

i) A discussion of any differences between its short-term fuel price forecasts and capacity price curve in the IRP filing, and the short-term fuel price forecasts and capacity price curve in its last power supply cost recovery proceeding.

j) Identification and justification of the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements used in the IRP. The utility shall identify its base case forecasts and a range of sensitivities for each such factor and explain how those sensitivities were identified. If the base case forecast(s) differs from recent previous forecasts submitted by the utility to the Commission in other cases, the utility shall provide an explanation for such differences.

k) 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 shallanalyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's generation fleet.

l) Estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and over the life of the facilities included in their IRP.

m) The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates.

n) An analysis that contains an individualized cost estimate for electric resources that were considered, including renewable alternatives, such as solar, wind, or solar plus storage, and such cost estimates for all alternative proposals, solicited or unsolicited, received by the utility.

o) Electricity market forecasts utilized.

p) Other documents and data underlying the IRP analysis.

Commented [A36]: DTE comment – request clarification. This could extend beyond the study period. Suggest updating to over study period

Commented [A37]: DTE comment: "An analysis" is vague. This section also seems duplicative of section g above

Commented [A38]: DTE comment: Duplicative of section j above

Appendix 1

I. Scope of Portfolio Build Plan Evaluated in Scenarios as follows (herein referred to collectively as portfolios):

   a. Portfolio 1: Previously approved portfolio (status quo; PCA in previously approved IRP) run in the MIRPP Scenario 1 (optimized through the current study period).
   b. Portfolio 2: Utility proposed course of action (PCA) portfolio run in MIRPP Scenario 1.
   c. Portfolio 3: Optimized portfolio in MIRPP Scenario 1.
   d. Portfolio 4: Optimized portfolio in MIRPP Scenario 1 with high load sensitivity.
   e. Portfolio 5: Reasonable Alternatives to the PCA presented by the utility in MIRPP Scenario 1.

II. The utility will provide the following facility/unit level data and total annual fleet data, in an Excel spreadsheet(s) expressed in total tons, to EGLE for:

   a. Emissions of the following:
      i. sulfur dioxide (SO2)
      ii. nitrogen oxides (NOx)
      iii. carbon monoxide (CO)
      iv. particulate matter (PM)
      v. lead (Pb)
      vi. mercury (Hg)
      vii. volatile organic carbon (VOC)
      viii. carbon dioxide (CO2)

   These data will be presented as raw numbers/units and as the aggregate change comparing the three portfolios - #1, #2 and #5. The methodology used to determine the emissions from the respective regional transmission organization purchases will be explained. The utility will propose a sample template of what would be provided in the IRP filing to EGLE for agreement 30 days before the filing.

III. Analyze all portfolios to identify and quantitatively assess the potential impacts to vulnerable communities (as defined collaboratively with EGLE). The utility will perform an Environmental Justice Screening and Mapping Tool (EJSCREEN) or the Michigan Environmental Justice Screening Tool (Mi EJSCREEN). The screening will include vulnerable communities within a 3-mile radius of each facility for all facilities. This quantitative assessment should address air emissions and early retirement of fossil fuel-fired facilities. ~~Explain how these considerations were considered in the utility's decision.~~

Commented [A39]: DTE comment: Suggest deleting, duplicative of VIII below

IV. Using the vulnerable communities identified in the analysis above, qualitatively assess the impacts of all portfolios including utility proposed early retirements of fossil fuel-fired facilities. The analysis should address water quality, waste disposal, and expected changes in land use for new or retiring resources to the extent known at the time of filing.

V. To determine health impact estimates for air emissions, the utility will use the environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE), the Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool, or a similar analytical tool with mapping features and spatial resolution down to at least the county level. Based on the pollutant parameters compatible with the chosen tool, this air emissions data analysis will be performed to provide health impact estimates to assess:

a. Overall fleetwide health impacts of utility proposed early retirement of fossil fuel-fired facilities and renewable energy adoption. Results, including impacts and associated costs, will be presented for portfolios #1, #2, and #5.

b. Impacts on vulnerable communities identified above (within a 3-mile radius). Results, including impacts and associated costs, will be presented for all five listed portfolios.

VI. If a decrease in PM2.5 emissions is not demonstrated at all electric generating unit(s) within a 6-mile radius of an identified disadvantaged community, including any new proposed units that could reasonably be expected to locate within the 6-mile radius, conduct dispersion modeling for PM2.5 including all electric generating unit(s) within a 6-mile radius of the identified disadvantaged community. The current emissions should be used to establish a baseline modeling demonstration by which to compare the future impacts of portfolio #2. Any dispersion analysis conducted pursuant to this item, doesn't necessarily need to be a refined analysis. A screening analysis employing reasonable assumptions is acceptable. How refined the analysis is at the discretion of the utility. The goal of this analysis is to assess how the ambient concentrations of PM2.5 in vulnerable communities may be affected and to encourage an assessment of ambient impacts in the siting of any new units.

VII. For resources located within the non-attainment areas, or an area that may be designated nonattainment based on reasonably known information at the time of filing, in the electric utility service territory, identify and assess their impact to the non-attainment status for the portfolio #2 listed above as compared to portfolio #1, and qualitatively support in testimony. The assessment should consider all nonattainment pollutants (i.e., SO2 and ozone), as well as their precursors (i.e., NOx and VOCs).

VIII. Narrative discussion of the quantitative and qualitative health and environmental impacts based on the analysis above, methodologies, data sources, and related observations. Explain how these considerations were considered in the utility's decision.

IX. Hold a technical conference with MPSC and EGLE staff within 30 days of the filing to discuss the environmental and emission related data included in the filing testimony, exhibits and workpapers.

Commented [A40]: DTE Comment – What is meant by "pollutant parameters compatible with the chosen tool"?

Commented [A41]: DTE Comment – What is the timeframe for this comparison? Need a definition.

Commented [A42]: DTE Comment – Any new proposed units do not have siting at the time of a filing which renders the required dispersion analysis meaningless for assessing net impacts. This type of analysis are best left for the permitting that will be required when new units are proposed for construction and the locations and characteristics of emissions are defined.

Commented [A43]: DTE Comment – The Company doesn't see value in dispersion modeling. Dispersion modeling provides no additional means to assess health impacts beyond the tools identified in V. above. Dispersion modeling provides a relatively inaccurate analysis of emissions impacts. Rather than require dispersion modeling as the method to compare impacts, introduce it as an example of how it can be done. If the utility analysis shows that this comparison of impacts can be completed using emissions data, across the fleet or at least at a county level why conduct dispersion modeling? to complete a dispersion analysis at a receptor level would be difficult in reconciling impacts vs benefits at each receptor location

Commented [A44]: DTE Comment – What is meant by "current emissions" as it relates to the year of the IRP filing?

Commented [A45]: DTE comment: This is duplicative with section XVII part e). Suggest deleting in one of the locations

CLEAN GRID ALLIANCE's FEEDBACK ON
MI POWER GRID STAKEHOLDER PROCESS for
INTEGRATED RESOURCE PROCUREMENT PARAMETERS &
FILING REQUIREMENTS

May 16, 2022

INTRODUCTION

Clean Grid Alliance's comments on the Filing Requirements and IRP Parameters address three points: [1] best practice methodologies for energy storage resources; [2] modeling of variable, clean energy resources as a single-bundled resource; and [3] utilities should describe how they intend to meet forecasted energy shortfalls.

COMMENTS

1. Modeling Scenarios, Sensitivities and Assumptions: Best Practice Methodologies for Energy Storage

The IRP Parameters document states that 'energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist." (IRP Parameters at 27 and 31.) Below, CGA presents best practices of storage modeling that should be included in the IRP Parameters document. Some of these best practices are established, and some are already included in the IRP Parameters document through other comments:

i. *Grid Services that can be provided by Energy Storage*: Energy storage is a scalable and flexible resource that can act in multiple ways. The modeling needs to account for its flexibility and scalability as it is used to support generation, transmission, distribution, and end-use operations. At a minimum, the modeling needs to account for frequency regulation and spinning reserves that energy storage can provide.

ii. *Sub-hourly modeling*: Sub-hourly modeling is needed to properly evaluate energy storage's production cost benefits. For administrative efficiency and due to computing limitations sub-hourly modeling may need to be performed for a period of time less than the 20 year period, and then extrapolated to and adjusted for the full analysis period.

iii. *Transmission Assumptions*: The transmission model needs to include a reasonable forecast of likely transmission expansion, and include sufficient system details to identify services a battery could provide that are locationally interdependent. In most instances, an IRP identifies generation expansion without identifying location. For energy storage, certain services and production cost analyses are locationally interdependent.

Below are best practices for energy storage modeling that, to a certain extent, are currently reflected in the draft IRP Parameters.

iv. *Costs*: Use reputable, up-to-date sources for capital and operation costs.

v. *Capacity Value*: Capacity value of storage should align with the effective load carrying capability estimates.

vi. *Scenarios/sensitivities*: Scenarios and sensitivities should evaluate events that would stress the system but have a reasonable likelihood of occurring, such as very high gas prices, adoption of carbon reduction targets, use of social cost of carbon, etc.

2. Resource Screen: Model Bundled and Hybrid Resources

When considering supply-side resources, the utility should bundle variable, clean energy resources into one resource. A bundled clean energy resource can either be a hybrid plant (example, solar and battery storage with a common meter or interconnection point) or two or more separate and individually operated variable, clean energy resources (a battery storage resource would be a potential resource to be included in the bundle). Not evaluating a bundle of variable, clean energy resources leads to a discrepancy between the IRPs forecast of the optimal selection of resources and the real world operation of the system if two or more separate clean energy plants are added to the utility's generation portfolio. A typical generation expansion model will add/select the lowest-cost resource after comparing specific supply-side resources. It evaluates a wind resource, a solar resource and a battery resource against that of other conventional supply-side resources. If all three resources are added -- wind, solar and battery resource -- they would complement each other, and more effectively meet energy and reliability requirements than they would individually. Thus, the generation model discounts or undervalues the actual capacity and energy value that two or more separate and individually operated clean energy plants could provide. Clean energy resources that are variable can provide a cumulative generation profile and cumulative zonal resource credits similar to a conventional resource at a comparable price, but they aren't always built and operated as one plant (i.e., a hybrid plant). The IRP generation expansion model needs to account for this discrepancy between adding individual variable, clean energy resources and the way that two or more of those resources would actually operate.

The generation expansion program should model bundled resources as if they were one plant. For example, the energy output profile would be the aggregate hourly energy output of the proposed bundle of variable, clean energy resources. The levelized cost of energy and levelized cost of capacity could be the generation-weighted average of the proposed bundle of variable clean energy resources.

3. Analyzing Resources that Meet Reliability and Energy Needs

The IRP Parameters and filing requirements address the utility's need to meet or exceed Planning Reserve Margins and Local Clearing Zone requirements, but nothing is noted in the IPA Parameters about planning to meet forecasted energy requirements. After planning to meet the aforementioned reliability requirements, the utility should discuss whether its generation portfolio will meet the forecasted energy needs. If it does not meet the forecasted energy need, the utility should provide a plan for meeting the forecasted energy shortfall and the cost-effectiveness of the options it considered when developing said plan. The importance of this type of planning will increase as the pentation of variable, clean resources increases.

These comments are respectfully submitted on behalf of Clean Grid Alliance

Sean R. Brady
Senior Counsel and Regional Planning Manager - East
CLEAN GRID ALLIANCE

Michigan Energy Innovation Business Council
115 W. Allegan, Suite 710
Lansing, MI 48933

Advanced Energy Economy
1010 Vermont Ave NW, Suite 1050
Washington, DC 20005

Dear Ms. Gibbs,

Advanced Energy Economy (AEE) and the Michigan Energy Innovation Business Council (Michigan EIBC) appreciate the opportunity to provide comments in response to the most recent draft updates to the Integrated Resource Planning Parameters and Filing Requirements, in MI Power Grid's Advanced Planning Processes Phase III workgroup. We continue to remain generally supportive of the overall updates Staff has made and we appreciate the improvements made with respect to the consideration of energy storage resources in IRP modeling. However, we remain concerned that the language pertaining to energy storage is not fully developed and, as written, cannot and will not most accurately and effectively enable the modeling of energy storage resources. Our comments, which are supplemental to previous comments submitted in this workgroup, provide recommendations on how to improve the consideration of storage in IRP modeling and provide multiple resources that reflect best practices.

If you have any further questions about these comments, please contact Ryan Katofsky and Laura Sherman.

Sincerely,

Dr. Laura Sherman
President
Michigan EIBC
laura@mieibc.org

Ryan Katofsky
Managing Director
Advanced Energy Economy
rkatofsky@aee.net

Comments

Energy storage resources are fundamental to the operation of a reliable and cost-effective grid, especially as the state moves toward higher adoption of renewable energy resources. Long-duration storage resources, capable of discharging at full rated capacity for longer than eight hours, can provide firming services during extended periods, while short-duration storage resources can meet critical needs during peak hours and provide dynamic balancing services. Storage, like other advanced energy technologies, will continue to see declining costs over time. Each of NREL's cost projection scenarios estimate substantial decreases in cost through 2050.[1] Despite these expected cost declines and the fact that storage may be the least cost, highest value resource, IRP modeling may fail to capture the full benefits that storage provides. We remain concerned that, as written, the draft IRP planning parameters and filing requirements do not adequately ensure that storage resources will be accurately and fully considered. This issue can be addressed in several ways.

1. Given that energy storage resources are already effectively modeled in IRPs across the country, we recommend deleting the phrase "to the extent that such guidelines exist" from Section VII under both Scenario #1 and Scenario #2.

2. There are several ways to strengthen the draft updates even further. It is our understanding that MPSC Staff is receiving technical assistance from the U.S. Department of Energy (DOE). In coordination with DOE's technical advisors, we recommend that the MPSC develop state-specific best practices (e.g., cost and operational assumptions, model settings) and apply them in the IRP process. Previous comments by Michigan EIBC and AEE have identified what those approaches might look like. Any such approach should consider existing resources such as:
    a. Lawrence Berkeley National Laboratory's "State of the Art Practices for Modeling Storage in Integrated Resource Planning"[2]

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[1] Cole, W., Frazier, W., Augustine, C. National Renewable Energy Laboratory. June 2021. "Cost Projections for Utility Scale Battery Storage: 2021 Update." Available at: https://www.nrel.gov/docs/fy21osti/79236.pdf

[2] Miller, C., Twitchell, J. and Schwartz, L. October 12, 2021. "State of the Art Practices for Modeling Storage in Integrated Resource Planning." Innovations in Electricity Modeling: Training for National Council on Electricity Policy. Available at: https://pubs.naruc.org/pub/CCBEFC58-1866-DAAC-99FB-3A405315FB9B.

b. The National Association of Regulatory Utility Commissions Resolution on Modeling Energy Storage and Other Flexible Resources[3]

c. Energy storage procurement models in California, Oregon, and Virginia[4,5]

d. State laws that require utilities to consider storage assets in the IRP process, such as Washington,[6,7] Oregon[8] and Arizona.[9]

e. Additional resources to consider include the Institute for Energy Innovation's Energy Storage Roadmap for Michigan,[10] an Energy Storage Association report on storage in IRPs,[11] and multiple reports from Pacific Northwest National Laboratory,[12] including one most recently referenced in DTE's technical workshop on energy storage modeling for its upcoming IRP.[13]

3. If the MPSC chooses to not develop its own best practices in the described manner, the above resources should at least be identified in the Appendix of the IRP planning parameters. These resources could be added under "*Section VIII. Michigan IRP Modeling Input Assumptions and Sources."* The Appendix should include a new section, devoted

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[3] National Association of Regulatory Utility Commissioners. November 2018. "EL-4/ERE-1 Resolution on Modeling Energy Storage and Other Flexible Resources." Available at: https://pubs.naruc.org/pub/2BC7B6ED-C11C-31C9-21FC-EAF8B38A6EBF.

[4] Stanfield, S., Petra, J. S., and Auck, S. B. Interstate Renewable Energy Council. April 2017. "Charging Ahead: An Energy Storage Guide for State Policymakers." Available at: https://irecusa.org/resources/charging-ahead-energy-storage-guide-for-policymakers/.

[5] Burwen, J. Energy Storage Association. 2020. "Energy Storage Goals, Targets, Mandates: What's the Difference?" Available at: https://energystorage.org/energy-storage-goals-targets-and-mandates-whats-the-difference/.

[6] Washington Administrative Code 480-100-620. Available at: https://app.leg.wa.gov/WAC/default.aspx?cite=480-100-620.

[7] Washington State Utilities and Transportation Commission. October 2017. "Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition." Dockets UE-151069 and U-161024 (Consolidated). Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=237&year=2016&docketNumber=161024.

[8] Washington State Utilities and Transportation Commission. October 2017. "Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition." Dockets UE-151069 and U-161024 (Consolidated). Available at: https://apiproxy.utc.wa.gov/cases/GetDocument?docID=237&year=2016&docketNumber=161024.

[9] Arizona Public Service Company. 2020 Integrated Resource Plan. Available at: https://www.aps.com/-/media/APS/APSCOM-PDFs/About/Our-Company/Doing-business-with-us/Resource-Planning-and-Management/2020IntegratedResourcePlan062620.ashx?la=en&hash=24B8E082028B6DD7338D1E8DA41A1563. pp. 22, 66-67.

[10] Institute for Energy Innovation for Michigan Department of Environment, Great Lakes, and Energy. March 2022. "Energy Storage Roadmap for Michigan." Available at: https://mieibc.org/wp-content/uploads/2022/03/IEI_EnergyStorageReport_FINAL.pdf.

[11] Energy Storage Association. 2018. "Advanced Energy Storage in Integrated Resource Planning." Available at: https://energystorage.org/wp/wp-content/uploads/2019/09/esa_irp_primer_2018_final.pdf.

[12] Cooke, A. L., Twitchell, J. B., O'Neil, R. S. Pacific Northwest National Laboratory. May 2019. "Energy Storage in Integrated Resource Plans." Available at: https://energystorage.pnnl.gov/pdf/PNNL-28627.pdf.

[13] Cooke, A., and Twitchell, J. Pacific Northwest National Laboratory. December 2021. "Emerging Best Practices for Modeling Energy Storage in Integrated Resource Plans: An overview and a comparison." Available at: https://ieeexplore.ieee.org/abstract/document/9632850/authors#authors

solely to this matter, numbered 18, and titled *"Best Practices for Energy Storage Modeling,"* and include all of the aforementioned resources.

4. The IRP Planning Parameters should recognize and include reference to the State's new energy storage target, as detailed in the recently released MI Healthy Climate Plan.[14] That plan adopts "a statewide storage target to deploy 4,000 Megawatts (MW) of grid scale storage by 2040 with a short-term target of 1,000 MW by 2025 and a medium-term target of 2,500 MW by 2030." It also calls for increased "consideration of energy storage resources in utility Integrated Resources Plans through accurate modeling."

   These targets should be included in the baseline of Scenario #2. As written, Scenario #2 currently "incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met." The energy storage target in the MI Healthy Climate Plan is an "announced state goal" and, as such, should fall under this scenario. Therefore, a bullet point should be added in Scenario #2 which reads:

   - *"Statewide, achieve 1,000 MW of energy storage by 2025, with an additional 1,500 MW added by 2030, with the ultimate goal of 4,000 MW by 2040."*

   If the energy storage target is not written directly into the baseline of Scenario #2, it should at least be included as a sensitivity. The sensitivity could read as follows:

   - *"Assume the state's energy storage target by 2040 is met, with interim targets reached in 2025 and 2030."*

5. The IRP Planning Parameters should ensure that IRP scenarios account for atypical weather conditions that occur at least as frequently as once in ten years or include a

[14] Michigan Department of Environment, Great Lakes, and Energy. April 22, 2022. "Draft MI Healthy Climate Plan." Available at: https://www.michigan.gov/egle/-/media/Project/Websites/egle/Documents/Offices/OCE/MI-Healthy-Climate-Plan.pdf?rev=d13f4adc2b1d45909bd708cafccbfffa&hash=99437BF2709B9B3471D16FC1EC692588.

stochastic analysis of atypical weather risks. Without this capability, capacity expansion models are unlikely to select portfolios that remain least-cost during the range of weather events that are likely to occur.

Critically, such a sensitivity should not be used to justify a deferral or avoidance of the emissions targets set by the state. Non-emitting resources, like energy storage, are available to address reliability risks if appropriately modeled. A sensitivity for Scenario #2 could read as follows:

- *"Model the impact of atypical weather conditions that occur at least as frequently as once in ten years, either via a load forecast adjustment or a stochastic analysis of weather risks. Needs should be met within the bounds of required emissions reduction targets."*

Electric Vehicles as Storage Assets

Under Scenarios #1 and #2 of the IRP Planning Parameters, there is a provision that "all storage resources are considered" and that distributed energy resources are broadly considered. It is important to ensure that this captures the capacity of electric vehicles (EVs) to serve as a grid asset through vehicle-to-grid (V2G) interoperability. In the draft IRP Planning Parameters, EVs are viewed primarily as a source of additional demand on the grid. However, given the time horizon of the IRP planning process, it is both appropriate and prudent for utilities to fully consider the potential for EVs to serve as resources for the grid. Below we suggest how this could be reflected in the IRP Planning Parameters and also provide several resources that could be included in the Appendix of the IRP Planning Parameters.

Vehicle-grid integration (VGI), which can include the use of time-of-use rates and demand response programs, encompasses both managed charging (V1G) and vehicle-to-grid (V2G). V2G involves the control of bidirectional power flows whereby the EV can be used as an active resource on the grid by feeding electricity back to it during periods of high demand, to, for example, avoid using fossil fuel resources to meet that demand. Charging or discharging an EV battery at specific times, in this manner, functions similarly to a stationary storage system. At the same time, the use of EVs as storage resources requires optimization that is different from stationary energy storage systems because the primary service being provided is mobility, which should not be impacted in a way that is not acceptable to the vehicle owner. As described below, existing V1G technology allows EVs to provide a number of customer services including demand reduction and demand response. As V2G technology evolves, EVs will likely be used for energy arbitrage, transmission and distribution deferrals, peak load reduction, back-up power, and a variety of ancillary services.

Even among the most conservative projections of EV adoption, the cumulative storage capacity contained in the batteries of Michigan driver's personal EVs, as well as within fleets of medium and heavy duty EVs, will quickly become relevant as a storage asset. As it stands now, Bloomberg New Energy Finance[15] estimates that there is 482 GWh of battery capacity in EVs currently on the road, globally, which is more than ten times the amount of installed stationary storage. Tapping into a fraction of the storage capacity of EVs through V2G technology could have enormous benefits for an electric grid with high renewable penetration. This emerging use case for EVs should therefore be considered in both Scenarios #1 and #2 of the IRP Planning Parameters, but especially the latter, which assumes "EV adoption reaches 50% of total vehicle sales by 2030 with a continuing trend toward 100% of vehicle sales." Throughout the IRP Planning Parameters, these vehicles should not be considered only as new load, but also, should be modeled by the utilities as potential sources of generation and storage. If the utilities are serious about detailing demand and energy forecasts and understanding "electrification, demand side resources, and customer owned distributed generation," then the potential of vehicles as both a demand side and supply side resource should be considered .

To facilitate discussion and understanding of vehicle-to-grid technologies as a grid resource, we recommend the addition of the following resources to "*Section VIII. Michigan IRP Modeling Input Assumptions and Sources"* under either section *"15 - Other Resources"* or *"17 - EV Forecasts:"*

[15] McKerracher, C., et al. Bloomberg New Energy Finance. 2021. "Electric Vehicle Outlook 2021" Available at: https://about.bnef.com/electric-vehicle-outlook/.

- *The Interstate Renewable Energy Council's "V2X Roadmap"*[16]
- *The Citizens Utility Board's "The ABCs of EVs: A Guide for Policy Makers and Consumer Advocates"*[17]
- *The ZEV Alliance's "Implementing Open Smart Charging"*[18]
- *The Institute for Energy Innovation's "Energy Storage Roadmap for Michigan"*[19]

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[16] Corchero, C., Sanmarti, M., Gonzalez-Villafranca, S., and Chapman, N. Interstate Renewable Energy Council. 2019. "V2X Roadmap." Available at: https://ieahev.org/wp-content/uploads/2021/08/Task28_additional.pdf.

[17] Cohen, M. The Citizens Utility Board. April 2017. "The ABCs of EVs: A Guide for Policy Makers and Consumer Advocates." Available at: https://citizensutilityboard.org/wp-content/uploads/2017/04/2017_The-ABCs-of-EVs-Report.pdf.

[18] Cutter, E., Dodson, T., Ferguson, N., et al. The ZEV Alliance. November 2019. "Implementing Open Smart Charging." Available at: https://zevalliance.org/implementing-smart-charging/.

[19] Institute for Energy Innovation for Michigan Department of Environment, Great Lakes, and Energy. March 2022. "Energy Storage Roadmap for Michigan." Available at: https://mieibc.org/wp-content/uploads/2022/03/IEI_EnergyStorageReport_FINAL.pdf.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to commence a collaborative to consider issues related to integrated resource and distribution plans.	))))	Case No. U-20633

COMMENTS OF THE
ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

I. INTRODUCTION

The Michigan Public Service Commission ("Commission") issued an Order on September 24, 2021 directing Commission Staff to begin Advanced Planning Phase III of the Integration of Resource, Distribution, and Transmission Planning workgroup. Specifically, this phase was to revisit the Michigan Integrated Resource Planning Parameters ("MIRPP"), integrated resource plan ("IRP") filing requirements, and Demand Response ("DR") and Energy Efficiency Studies which are required to be evaluated every five years under MCL 460.6t(1).

The Commission directed Staff to create a redline version of the MIRPP published on November 21, 2017, that reflects the recommendations developed through the Integration of Resource, Distribution, and Transmission Planning workgroup to date, as well as feedback from stakeholders and the directives for building a carbon-neutral Michigan pursuant to Executive Directive 2020-10. Pursuant to this direction Staff conducted a workgroup on April 26, 2022 and solicited comments on the Draft IRP Filing Requirements and Draft MIRPP. Pursuant to that solicitation the Association of Businesses Advocating Tariff Equity ("ABATE") provides the following comments.

II. COMMENTS

A. Draft IRP Filing Requirements

1. Approval of Costs

In Section II ("Renewable Resources") the first sentence ("The utility shall file data consistent with its renewable energy plan") should be changed to reflect the utility's ***approved*** renewable energy plan.

2. IRP Filing, Data, and Documentation

a. Section I – Executive Summary

In subparts (i) and (j), the scenario and sensitivity used for the energy and pollutants chart must be specified and should reflect the Company's best estimate of the future operating conditions and regulatory environment. The scenario and sensitivity assumptions will dictate generation and emissions from resources, thus the assumptions must be specified.

A new subpart should also be added to discuss the estimated costs of the PCA. Suggested language is as follows:

> The Company shall include a discussion of the estimated costs of the PCA, including but not limited to, the NPVRR of the PCA, an estimate of the annual cost increases/decreases of the PCA under the same scenario and sensitivity as the stacked bar graph for energy required under subparts (i) and (j). This section could be a general summary of Section (XVI) Rate Impact and Financial Information.

b. Section XII – Fuel

Two new sections should be added to capture fuel price forecasts and delivered fuel prices for fuels other than oil, coal, and natural gas. It is possible that nuclear fuel, hydrogen, or other fuels could be used by a Company's PCA or by potential resource options.

c. Section XIV – Modeling Results

A new section should be added to require a loss of load probability analysis. Suggested language is as follows:

> The utility must provide a detailed demonstration that its PCA and any alternative resource plans will meet all applicable resource adequacy requirements. This analysis should definitively demonstrate that the resource plans will meet or exceed the 1-in-10 loss of load probability standard under resource dispatch assumptions vastly similar to actual operations within the utility's RTO, rather than assuming the utility's balancing area is an island with access to outside resources via transmission. For utilities operating in the MISO RTO, a separate analysis should be conducted that considers and incorporates a seasonal resource adequacy construct.

d. New Section.

A new section should be added to ensure the outcome of an IRP proceeding can be evaluated against the Company's filed PCA in terms of the IRP filing requirements and the considerations set out in MCL 460.6t(8)(a) (i.e.: (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii) competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective). In other words, the IRP filing requirements should require an analysis accompany any final resolution of an IRP (including, but not limited to, a Commission Order approving an IRP under MCL 460.6t(7) or a filed settlement agreement) in an IRP proceeding which, at a minimum, shows performance of that final resolution with respect to the criteria contained in MCL 460.6t(8) and the filing requirements compared with the utility's original filed PCA. This analysis should also take into account impacts associated with meeting sustainability targets. Suggested language is as follows:

> If an IRP proceeding results in a recommended resource portfolio that differs from those provided in the Company's filed IRP, the Company is required to provide information regarding how this new recommended resource portfolio compares with the Company's filed PCA in terms of the considerations set out in MCL 460.6t(8)(a) (i.e. (i) resource adequacy and capacity to serve anticipated peak electric load, applicable planning reserve margin, and local clearing requirement; (ii) compliance with applicable state and federal environmental regulations; (iii)

competitive pricing; (iv) reliability; (v) commodity price risks; (vi) diversity of generation supply; and (vii) whether the proposed levels of peak load reduction and energy waste reduction are reasonable and cost effective) and filing requirements sections (I) (Executive Summary), (XIV) (Modeling Results), (XV) (Proposed Resource Plan), (XVI) (Rate Impact and Financial Information), (XVII) (Environmental Considerations and Environmental Justice). This information must be provided within thirty (30) days of the Commission's 300 day order recommending changes to a filed IRP under MCL 460.6t(7) or, in the case of a proposed settlement agreement, prior to a settlement agreement being filed for Commission consideration and approval. This comparative analysis and information is necessary so that stakeholders and the Commission may understand the impacts of any approved resource portfolio relative to the Company's PCA, including all assumptions and data underlying the same.

B. Michigan Integrated Resource Planning Parameters

The utility should be required to file an additional Scenario with sensitivities that provides the best indication of the utility's opinion of the actual operational and regulatory environment throughout the study period. Absent the requirement of such a scenario, the modeling results provided for Scenarios #1 & #2 may not accurately depict the cost implications of a utility's proposed course of action.

III. CONCLUSION

Pursuant to Staff's solicitation of feedback ABATE recommends Staff consider and incorporate the comments set out above.

Respectfully submitted,

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ACEEE comments and recommended edits 05/12/22 (see pages 27-34 and page 37)

Draft 2022

Table of Contents

I. Executive Summary

This Michigan Integrated Resource Planning Parameters document was developed as a partof the implementation of the provisions of Public Act 341 of 2016 (PA 341), Section 6t. This document includes two integrated resource plan (IRP) modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Upper and Lower Peninsulas. 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 beviewed 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 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 and Energy Waste Reduction Potential Studies were completed August of 2021. Both studieshave an influence on integrated resource planning and are

incorporated into the Commission's Docket (Case No. U-21219[1]) for the 5-year update pursuant to 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. This is the first 5-year update. The next 120-day proceeding to conduct these assessments and gather input shouldcommence in July 2027.

II. Background

On December 21, 2016, PA 341 was signed 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 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 MPSCfor review and approval.

At the conclusion of a stakeholder process and issuance of draft Michigan Integrated Resource Planning Parameters (MIRPP), the Commission adopted the MIRPP on November 21, 2017, in Case No. U-18418.

Pursuant to PA 341, the MPSC and the Department of Environment, Great Lakes and Energy (EGLE) began a second collaborative process as part of MI Power Grid Phase II – Integration of Resource/Distribution/Transmission Planning on September 24, 2020, with state-wide participation from a wide-range of stakeholders (listed in Appendix A). On October 29, 2020, the Commission issued an order in Case No. U-20633 directing Staff to also work with stakeholder groups to determine how to update IRP planning parameters and filing requirement to take into account the goals set by Michigan's utilities and how

[1] Add link once we have a docket.

these goals align with the greenhouse gas emissions targets set by Governor Whitmer. Stakeholder sessions discussed many aspects of PA 341 Section 6t including:

i. Environmental Policy
ii. Forecasting
iii. Transmission
iv. The Regional Energy Market
v. Distributed Energy Resources
vi. Economic valuation
vii. Generation Diversity
viii. Risk Assessment

Stakeholders were invited to participate by providing comments and feedback during and after every stakeholder session. met regularly from December 2021 to late April 2022 to discuss how to update various subsections of PA 341 Section 6t. Further details on the stakeholder sessions are included on the MPSC's web page for Phase III of the MI Power Grid initiative.[2]

The Commission released an earlier draft of this document with a Commission Order initiating Case No. U-21219 on July, 2022. Interested parties were provided an opportunity to file comments and reply comments in Case No. U-21219. The Commission has considered the comments and reply comments and has incorporated several changes herein.

III. 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 conducted by Guidehouse Inc. (Guidehouse) for electricity and natural gas for the entire State of

[2] https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93320-508709--,00.html.

Michigan. This study's objective was to assess the potential in the residential, commercial, and industrial sectors, with the addition of small commercial, multifamily, and low-income segments, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. Measure and market characterization data was input into Guidehouse's Demand Side Management Simulator (DSMSim™) model, which calculates technical, economic, and achievable potential across utility service areas in Michigan for more than 600 measure permutations. Results were developed and are presented separately for the Lower and Upper Peninsulas. These results will be used to inform EWR goal setting and associated program design for the MPSC.[3]

Scenario #1: Reference–Estimates of achievable potential calibrated to 2021 total program expectations and refined using relative savings percentages at the end use and high impact measure-level with 2019 actual achievements. Key assumptions include non-low-income measure incentives of 40% of incremental cost (low-income segments incentivized at 100% of incremental cost) and administrative costs representing 33% of total utility program spending.

Scenario #2: Aggressive–Increased measure incentives and marketing factors and decreased program administrative costs. Analyzed measure incentive levels to determine the 1.0 Utility Cost Test (UCT) ratio tipping point. Developed measure-level incentive estimates based on these results and adjusted where necessary to ensure program-level cost effectiveness. Increased marketing factors above calibrated values for specific end use and sector combinations.

Scenario #3: Carbon Price–Acknowledging the regulatory uncertainty around carbon price legislation, provides a high-level fuel cost adder, ramping up through time as the probability of regulatory action increases. This scenario provides insight into the sensitivity of EWR savings potential to avoided costs. Due to the uncertain nature of carbon pricing legislation, the scenario is not related to specific program or policy recommendations.

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[3] MI EWR Potential Study MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov), Retrieved December 8, 2021.

Increased electricity ($/MWh) and natural gas ($/therm) avoided costs by 50% in 2021, escalating with a 2.5% multiplier growth until a 100% increase was met.

IV. Demand Response Potential Study[4]

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

The MPSC issued a request for proposal for the DR potential study in May of 2020. Bids were received and evaluated and a contract for the study was awarded to Guidehouse Inc. in August of 2020. The DR potential study assessed DR potential in Michigan from 2021 to 2040 and was conducted in conjunction with the energy waste reduction (EWR) potential study. The DR potential study was completed in September of 2021.

The objective of the DR potential assessment was to estimate the potential for cost-effective DR as a capacity resource to reduce customer loads during peak summer periods. Additionally, the study assessed electric winter peak reduction potential and natural gas DR potential. DR potential estimates were developed for both the Lower Peninsula and the Upper Peninsula.

The DR potential and cost estimates were developed using a bottom-up analysis. The analysis used customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR program information from Michigan utilities, the latest available information from the industry on DR resource performance and costs. These sources provided input data to the model used to calculate total DR potential across Michigan.

The DR potential study was a collaborative process wherein the MPSC, Guidehouse, and stakeholders worked together to ensure the study reflected current Michigan market trends. Three virtual stakeholder meetings were held during the study which provided

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[4] 2021 Energy Waste Reduction and Demand Response Statewide Potential Study, https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/demand-response-potential-study/

stakeholders with an update on study progress and an opportunity to provide feedback to Guidehouse and MPSC Staff.

V. State and Federal Environmental Regulations, Laws and Rules

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

Section 460.6t (1) (c)

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 (USEPA) to set NAAQS for six criteria pollutants that havethe potential of harming human health or the environment. The NAAQS are rigorously vetted bythe scientific community, industry, public interest groups, and the public. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standardsare set at a level that is protective of human 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 everyfive years by the Clean Air Scientific Advisory Committee. The six criteria pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.[5]

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

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 notabide by the Clean Air Act requirements to reign in the emissions of the pollutants are subject toUSEPA 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 USEPA for approval into the State Implementation Plan (SIP), and ensuring attainment occurs bythe 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 USEPA strengthened the primary NAAQSfor SO_2, establishing a new 1-hour standard of 75 parts per billion (ppb).

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

In May 2016, Michigan Department of Environment, Great Lakes, and Energy (EGLE) submitted its SO2 State Implementation Plan (SIP) strategy for southern Wayne County to the USEPA for final approval. This SIP was the strategy for bringing the area into compliance with the health-based NAAQS for SO2. Due to a lawsuit related to a portion of the SIP, USEPA is pursuing a federal implementation plan (FIP) for the non-attainment area, the action of which is still underway. In January 2022, USEPA made the formal determination that southern Wayne County did not attain the SO2 NAAQS by the 2018 deadline.

USEPA is working to complete the FIP and expects that it will be available for public comment sometime in winter of 2022. Following the approval of the FIP, EGLE will work

to incorporate its provisions into the SO2 SIP. Once all of the elements of the SIP have been implemented, EGLE plans to pursue a redesignation request for southern Wayne County.

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.

To better understand the quality of the air in the non-attainment area, tow monitors were installed in the vicinity in November 2016. The monitoring data has consistently shown SO2 levels in the area to be below the SO2 NAAQS. The Clean Air Act allows a state to submit a Clean Data Determination (CDD) to the USEPA if air monitors show three consecutive years of attaining data in a non-attainment area. This action waives the requirement for the state to produce a SIP for the non-attainment area.

EGLE determined that the CDD criteria had been met for the St. Clair non-attainment area and submitted a CDD to USEPA in July 2020, waiving the SIP requirement for the area. EGLE’s CDD was approved by USEPA in December 2021. Upon shutdown of the St. Clair Power Plant in May 2022, EGLE expects to submit a redesignation request to USEPA for the St. Clair County non-attainment area as well.

Round three designations were to address all remaining undesignated areas by December 31, 2017. The USEPA 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 USEPA 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, were also designated as unclassifiable/attainment.

Ozone Non-Attainment Areas: In 2015, the USEPA strengthened the primary NAAQS for ozone, establishing a new 8-hour standard of 70 ppb.

On August 3, 2018, Michigan was designated marginal non-attainment for the 2015 ozone NAAQS in four areas (ten counties) of the state. In southeast Michigan, the seven-county area encompassing Livingston, Macomb, Monroe, Oakland, St. Clair, Washtenaw, and Wayne counties and on the west-side, two partial counties including Allegan and Muskegon and one full county, Berrien were found to have design values[6] exceeding the new ozone NAAQS of 70 ppb. This classification established an attainment deadline and attainment plan submittal date of August 3, 2021. In addition to the requirement to attain by this deadline, there are also 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 attain the standard, monitoring values over the three-year period between 2018 and 2020 must have design values at or below the standard of 70 ppb.

In the fall of 2021, EGLE began working on a redesignation request for the seven-county southeast Michigan nonattainment area. Although design values for the three-year period between 2018 and 2020 did not show attainment with the 2015 ozone NAAQS, the design values for the three-year period between 2019 and 2021 did attain. The redesignation request was submitted to USEPA in January 2022, and approval is expected in late spring/early summer 2022. The three western non-attainment counties (partial Muskegon and Allegan and full county Berrien) did not attain the standard. It is expected that USEPA will reclassify or “bump up” those counties from marginal to moderate non-attainment. A reclassification from marginal to moderate extends the attainment deadline to August 2024; however, a classification of moderate requires additional actions to reduce emissions to attain the standard. Required moderate nonattainment planning elements include (but are not limited to) major source reasonably available control technology, 15% reasonable further progress, and an attainment demonstration.

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

[6] The design value is the three-year average of the 4th highest 8-hour ozone value)

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 governsthe 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 (April through October). 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. The USEPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May 2017. The state currently has Good Neighbor obligations for the 2015 ozone standard.

On March 15, 2021, USEPA finalized the revised CSAPR rule update for the 2008 ozone NAAQS. Starting with the 2021 ozone season, the revised rule reduced the emission budgets and therefore allocation of NOx allowances from power plants in 12 states, including Michigan. The revision includes adjusting these 12 states emissions budgets for each ozone season from 2021 through 2024.

EPA establishes that the revised CSAPR update will reduce NO_x emissions from power plants in 12 states in the eastern United States by 17,000 tons in 2021 compared to projections without the rule, yielding public health and climate benefits that are valued, on average, at up to $2.8 billion each year from 2021 to 2040.

Mercury and Air Toxics Standards – Section 302 of the Clean Air Act requires the USEPA 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 EGLE. In June 2015, the United States Supreme Court found that the USEPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the District of Columbia Circuit Court of

Appeals ruled that MATS may be enforced as the USEPA modifies the rule to comply with the United States Supreme Court decision. The deadline for MATS compliance forall electric generating units was April 16, 2016.

In December 2015, in response to the United States Supreme Court's direction, the USEPA published a proposed supplemental finding that a consideration of cost does not alter their previous determination that it is appropriate and necessary to regulate air toxic emissions from coal- and oil-fired EGUs. The proposed supplemental finding was based on an evaluation of several cost metrics relevant to the power sector and also considered public comments. USEPA found that the cost of compliance with MATS was reasonable and that the electric power industry could comply with MATS and maintain its ability to provide reliable electric power to consumers at a reasonable cost. USEPA's supplemental cost finding was finalized in April 2016.

In May 2020, USEPA completed a reconsideration of the April 2016 appropriate and necessary finding for the MATS, correcting flaws in the approach considering costs and benefits while ensuring that HAP emissions from power plants continue to be appropriately controlled. The agency also completed the CAA required residual risk and technology review for MATS. Following that reconsideration, USEPA concluded that the consideration of cost in the 2016 Supplemental Finding was flawed. Specifically, they found that what was described in the 2016 Supplemental Finding as the preferred approach, or "cost reasonableness test," did not meet the statute's requirements to fully consider costs and was an unreasonable interpretation of the CAA mandate. Power plants were already complying with the standards limiting emissions of mercury and other HAPs, and that final action leaves those emission limits in place and unchanged.

In January 2022 USEPA issued a proposal to reaffirm that it remains appropriate and necessary to regulate HAPs, including mercury, from power plants after considering cost. This action revokes the May 2020 finding that it was not appropriate and necessary to regulate coal- and oil-fired power plants under CAA Section 112 which covers toxic air pollutants. USEPA reviewed the 2020 finding and considered updated information on both the public health burden associated with HAP emissions from coal- and oil-fired power plants as well as the costs associated with reducing those emissions under the

MATS. After weighing the public risks posed by these emissions to particularly exposed and sensitive populations, against the costs of reducing HAP emissions, USEPA is proposing to conclude that it remains appropriate and necessary to regulate these emissions.

CAA 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 CAA for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the USEPA 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.[7]

CAA Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources - Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the CAA requires the USEPA to establish standards for certain existing industrial sources. The final Clean Power Plan (CPP), promulgated on October 23, 2015, addressed carbon dioxide emissions from EGUs. The CPP 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.[8]

On February 9, 2016, the United States Supreme Court issued five orders granting a stay ofthe Clean Power Plan pending judicial review. On March 28, 2017, President Trump signed anExecutive Order directing the USEPA 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

[7] 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.

[8] 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.

cases in abeyance pending the USEPA's review of both rules, including through the conclusion of any rulemaking process thatresults from that review.

On June 19, 2016, the USEPA promulgated the Affordable Clean Energy (ACE) Rule which replaced and repealed the Clean Power Plan. The ACE rule established emission guidelines for states to use in developing plans to limit carbon emissions at their coal-fired electric generating units (EGU); but did not establish specific carbon emission reduction goals. The ACE rule focused on an "inside the fence line" best system of emission reduction approach to emission reductions in the form of heat rate improvements at each EGU. On January 19, 2021, the United States Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it back to the USEPA for further proceedings consistent with the Court's ruling. On October 29, 2021, the United States Supreme Court agreed to grant a writ of certiorari for petitions for review of the January 2021 decision of the United States Court of Appeals for the District of Columbia Circuit to strike down USEPA's 2019 ACE Rule. Four pending petitions before the United States Supreme Court were filed earlier in 2021 by a coalition of nineteen states led by West Virginia, the State of North Dakota, the North American Coal Corporation, and Westmoreland Mining Holdings, LLC. The Supreme Court is expected to hear the four combined cases in its current term with a ruling expected in late spring or early summer 202~~1~~2.

Although there are not currently any rules regulating carbon emissions from existing Electric Generating Units (EGU); due to the USEPA's 2009 endangerment finding on greenhouse gasses, and in light of the current reduction goals on carbon neutrality at both state and federal levels, utilities should address their anticipated greenhouse gas emissions with those carbon neutrality reduction goals in mind.

Greenhouse Gas Reporting Program – The Greenhouse Gas Reporting Program (codifiedat 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 USEPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year. The USEPA 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 standardsfor 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 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 improvevisibility, 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 timeto 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, andammonia. 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 eachsource-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 thatmay 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 USEPA. In 2005, the USEPA published the guidelines for BART determinations. Michigan has met the initial BART determination requirements. In December 2016, the USEPA issued a final rule setting revised and clarifying requirements for periodic updatesin state plans. The next periodic update was due July 31, 2021. EGLE

has submitted the periodic update and it is currently being reviewed by USEPA. 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 **US**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 USEPA established requirements for the safe disposal of coal combustion residuals (CCR) produced at electric utilities and independent power producers. These requirements were established under Subtitle D of RCRA and apply to coal combustion residual landfills andsurface impoundments. Michigan electric utilities must comply with these regulations.

In July 2016, the USEPA Administrator signed a direct final rule and a companion proposal to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under Subtitle D (Non-hazardous solid waste). These revisions were completed in response to a partial vacatur ordered by the United States Court of Appeals for the District of Columbia Circuit on June 14, 2016. This direct final rule became effective on October 4, 2016.

In July 2018, the USEPA finalized certain revisions to the 2015 regulations for the disposal of CCR in landfills and surface impoundments to provide states with approved CCR permit programs under the Water Infrastructure Improvements for the Nation (WIIN) Act or USEPA (where USEPA is the permitting authority) the ability to use alternate performance standards and to revise the groundwater protection standards for four constituents in Appendix IV to part 257 for which maximum contaminant levels (MCLs) under the Safe Drinking Water Act had not been established. The revision also provided facilities which are triggered into closure by the regulations additional time to cease receiving waste and initiate closure. This additional time was meant to better align the CCR rule compliance

dates with the Effluent Limitations Guidelines and Standards Rule for the Steam Electric Power Generating Point Source Category.

In September 2020, the USEPA finalized amendments to the part 257 regulations. First, the USEPA finalized a change to the classification of compacted-soil lined or “clay-lined” surface impoundments from “lined” to “unlined” under § 257.71(a)(1)(i), which reflected the vacatur ordered in the Utility Solid Waste Activities Group (USWAG) decision. Secondly, USEPA finalized revisions to the initiation of closure deadlines for unlined CCR surface impoundments, and for units that failed the aquifer location restriction, found in §§ 257.101(a) and (b)(1). These revisions addressed the USWAG decisions with respect to all unlined and “clay-lined” impoundments, as well as revisions to the provisions that were remanded to the Agency for further reconsideration. Specifically, USEPA finalized a new deadline of April 11, 2021, for CCR units to cease receipt of waste and initiate closure because the unit was either an unlined or formerly “clay-lined” CCR surface impoundment (§ 257.101(a)) or failed the aquifer location standard (§ 257.101(b)(1)). With this action, USEPA also finalized revisions to the alternative closure provisions, § 257.103. The revisions granted facilities additional time to develop alternative capacity to manage their waste streams (both CCR and/or non-CCR), to achieve cease receipt of waste and initiate closure of their CCR surface impoundments.

In November 2020, the USEPA published the CCR Part B final rule which allowed a limited number of facilities to demonstrate to USEPA or a participating state director that, based on groundwater data and the design of a particular surface impoundment, the unit had and will continue to ensure there is no reasonable probability of adverse effects to human health and the environment. The regulations stated that facilities had until November 30, 2020 to submit applications to USEPA for approval, but given the effective date for the final rule was December 14, 2020, USEPA accepted revisions or applications until December 14, 2020.

In October 2020, USEPA issued an advanced notice of proposed rulemaking seeking input on inactive surface impoundments at inactive electric utilities, referred to as "legacy CCR surface impoundments". The information and data received will assist in the development of future regulations for these CCR units.

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 USEPA promulgated rules under Section 316(b) of theClean 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 USEPA 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 aclosed-cycle, recirculating cooling system.

Following a previously promulgated version of the rules and judicial remand, the regulationsfor 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. Therules do not specify national BTA standards for minimizing entrainment mortality, but instead require that EGLE establish the BTA entrainment requirements for a facility on a site-specificbasis. 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 mustprovide 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, facilitieswill need to achieve the impingement and entrainment mortality standards as soon as practicableaccording to the schedule of requirements set by EGLE 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 (ELG) 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 reviewchallenging the regulations were consolidated in the United States Court of Appeals for the FifthCircuit on December 8, 2015. On April 25, 2017, the USEPA issued an administrative stay of the compliance dates in the ELGs and standards rule that had not yet passed pending judicial review. In addition, the USEPA requested, and was granted, a 120-day stay of the litigation (until September 12, 2017) to allow the USEPA to consider the merits of the petitions for reconsideration of the Rule. On August 11, 2017, the USEPA provided notice that it would conduct a rulemaking to revise the new, more stringent BTA effluent limitations and Pretreatment Standards for Existing Sources in the 2015 rule that apply to bottom ash (BA) transport water and flue gas desulfurization wastewater (FGD). The EPA published the regulations on October 13, 2020, finalizing the revisions for these two wastewaters allowing for less costly technologies, a two-year extension of the compliance time frame and for meeting the requirements, and adding subcategories for both wastewaters. The subcategories included a voluntary incentive program for more restrictive limitations for FGD wastewaters with a longer compliance schedule, and an allowance that electric generating units that decommission by December 31, 2028, need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities. The earliest date for compliance with bottom ash and FGD wastewaters was set for October 13, 2021, but no later than December 31, 2025, unless the facility announces compliance with an optional program. In addition, the EPA published an announcement on August 3, 2021, on its decision to undertake additional rulemaking to again revise the SEEG. As part of the rulemaking process, the EPA will determine whether more stringent effluent limitations and standards are appropriate and consistent with the technology-forcing statutory scheme and the goals of the Clean Water Act. EPA intends to publish the proposed rulemaking for public comment in the fall of 2022. On September 18, 2017, the 120-day administrative stay was lifted postponing certain compliance deadlines. The earliest date for compliance with SEEG was November 1, 2020.

On August 31, 2020, USEPA finalized a rule revising the regulations for the Steam Electric Power Generating category (40 CFR Part 423). The rule revises requirements for two specific waste streams produced by steam electric power plants: FGD wastewater and BA transport water. In the revised rule, USEPA delays the compliance deadlines for BA transport water and FGD wastewater two years to December 31, 2025. In addition, the revised rule includes a voluntary incentive program that provides additional time, until December 31, 2028, for facilities that implement additional processes that achieve more stringent limitations and also has an allowance that electric generating units that decommission by December 31, 2028 need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities.

State Rules and Laws:
The majority of Michigan's environmental regulations/laws/acts were consolidated into the Natural Resources and Environmental Protection Act (NREPA) of 1994, Public Act 451 as amended (Act 451). Act 451 is organized into sections called "Parts" and serves "to protect the environment and natural resources of the state; to codify, revise, consolidate, and classify laws relating to the environment and natural resources of the state; to regulate the discharge of certain substances into the environment; to regulate the use of certain lands, waters, and other natural resources of the state; to protect the people's right to hunt and fish; to prescribe the powers and duties of certain state and local agencies and officials; to provide for certain charges, fees, assessments, and donations; to provide certain appropriations; to prescribe penalties and provide remedies; and to repeal acts and parts of acts."

Michigan Mercury Rule – The purpose of the Michigan Mercury Rule (MMR) is to regulatethe 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 CCR as a solid waste. It requires any CCR that will remain in place in asurface impoundment or landfill be subject to siting criteria, permitting and licensing of the disposal area, construction standards for the disposal area, groundwater monitoring, correctiveaction, and financial assurance and post-closure care for a 30-year period. The disposal facilityis required to maintain the financial assurance to conduct groundwater monitoring throughout the post-closure care 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 InfrastructureImprovements 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. Under the amendment, 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. In 2018, Part 115 was amended to include the majority of the RCRA regulations would be enforced by states and the CCR units would not be subject to the dual regulatory structure. In 2018, Part 115 was amended to include the majority of the RCRA rule, including the regulation of CCR surface impoundments used for

storage. Michigan's request for state program approval is currently under review by the USEPA.

To comply with PA 341 Section 6t (5) (m)
"How the utility will comply with all applicable state and federal environmental regulations, lawsand 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 ofcompliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's 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 theMichigan 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.

VI. 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 reservemargins 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 intolocal resource zones (Zones) with the majority of the Lower Peninsula in Zone 7 and the UpperPeninsula combined with a large portion of Wisconsin in Zone 2, as shown in Appendix B. Theunshaded 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.[9] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins 2022 through 2031" for the entire footprint.[10] MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report.[11] 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 the LOLE requirement while fully using the Capacity Import Limit for such."[12] The Local ClearingRequirement for each zone is reported annually with the MISO planning resource auction resultsin April.[13]

For the southwest corner of the Lower Peninsula, in PJM's territory,[14] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[15] PJM outlines requirements for an Installed Reserve Margin, similar to MISO's planning reserve margin on aninstalled capacity basis, and a Forecast Pool Requirement on an unforced capacity basis, similarto MISO's planning reserve margin on an unforced capacity basis. PJM also specifies 27 LocalDeliverability Areas somewhat similar to MISO's local resource zones.

[9] MISO 2022-2023 Loss of Load Expectation Study Report published on November 1, 2021

https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[10] 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.

[11] 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.

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

[13] MISO Planning Resource Auction results, April 2021

https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

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

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

PJM publishes a Reserve Requirement Study [16] annually in October containing the requirements for generator owners andload 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 capacitydemonstration 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 through2021. 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, toestablish 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 utilityIRP filings should be consistent with the requirements of the State Reliability Mechanism underSection 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiated to implement these provisions.

VII. 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, twomodeling scenarios are required. Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other

[16] PJM Reserve Requirement Study, October 2021.

https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx

jurisdictions. Due to the provisions in PA 341Section 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

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario directionally aligns with MISO's December 2021 Futures Report, Future 1 and reflects substantial achievement of state and utility announcements including generation retirements and environmental goals. This scenario incorporates 100% of utility integrated resource plan (IRP) retirement announcements and retirement assumptions throughout the MISO footprint, as identified in MISO Future 1. For the utility performing the analysis, the generation unit retirement assumptions may vary for only the generation units the utility has decision making authority. As subsequent MISO Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 1 of the December 2021 report may be used. This scenario assumes that CO2 emissions decline, driven by state goals and utility plans throughout the MISO footprint creating at least a 63% carbon reduction by 2040 from the baseline year of 2005 for the MISO region. This trajectory of carbon reduction is expected to continue beyond 2040.

This scenario assumes that demand and energy growth are driven by existing economic factors, with moderate electric vehicle (EV) adoption and customer electrification, resulting in moderate MISO footprint wide demand and energy growth rates. Utilities should use the most recent United States Energy Information Administration (EIA) Annual

Energy Outlook (AEO) Reference Case[17] or other reputable source for forecasted EV adoption rates. If the utility does not use EIA AEO then the EV forecast information must be provided within the utility IRP filing. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change, [18] electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.

*Note: Scenario aligns with MISO Future 1 from the December 2021 MISO Futures Report. If, in the future, MISO Futures significantly change, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 1.

- Natural gas prices utilized are consistent with the Reference Case projections from the United States Energy Information Administration's (EIA) most recent Annual Energy Outlook.[19]
- Moderate EV adoption and customer electrification result in moderate footprint-wide demand and energy growth. Within Michigan, EV and electrification forecasts should be blended with historical sales such that after 3 years, Michigan's load and demand increase reflects the source forecasts for EV and electrification technologies. Load profiles of EVs and electrification technologies should be clearly delineated and presented individually such that it is clear how they each impacted the overall energy and demand forecast. EV forecasts should be based off the Reference Case in the most recent EIA AEO. Electrification technology

[17] Electric Vehicle adoption as forecasted in the most recent EIA AEO East North Central Census Region Reference Case, http://www.eia.gov/outlooks/aeo/tables_ref.php

[18] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[19] 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 include delivery costs from Henry Hub to the point of delivery.

forecasts should be based off of either established proprietary forecasts or publicly available data.

- Resource assumptions: Assume MISO Future 1 retirements for existing thermal and nuclear generation resources published in the most recent Futures Report should be used when available along with recent public announcements. Specific new units will be modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON), IRP cost pre-approval, or signed generator interconnection agreement (GIA). Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO) should also be used. Generic new resources are assumed consistent with the scenario description, considering anticipated new resources currently in generation interconnection queue, and should be chosen based upon economics.
- 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 participating in the State EWR Program, 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.~~[20]~~
- Technology costs and limits to the total resource amount available for EWR and demandresponse programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Existing renewable energy and storage production tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.

~~[20] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)~~

Commented [MK1]: This modeling provision makes the inputs and assumptions used regarding these demand-side resources critically important. If incorrect or unnecessarily pessimistic inputs and assumptions are utilized, the modeling will select less of the EWR resource than would actually be desirable.

In that regard, solely referencing the 2021 Guidehouse study presents a serious problem.
As I have explained elsewhere https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002HlsgAAC that study contains a number of unduly limiting assumptions, and greatly understates the EWR potential. e.g., to put some numbers on this, that study claimed that under their so-called "Aggressive Scenario" that EWR potential only increased from a "base case" average of 1.40% per year to just 1.48% per year over the first 10 years! (In contrast, the 2017 'Lower Peninsula' EWR potential study by GDS, in their "High Assumptions" scenario, found an average EWR potential increased from a base case of 1.44% to 2.13% per year over the first 10 years.)

I strongly recommend that rather than footnote the 2021 study here, that the bullet from the next page be inserted below this bullet, as I have shown here.

- All storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist.[21]
- 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 demandresponse programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.~~
- Technology costs for solar, storage, and other emerging technologies decline with commercial experience consistent with NREL or other publicly available reputable sources.
- Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Commented [MK2]: Moved to previous page.

Scenario #1 Sensitivities:

1. Fuel cost projections
   (a) Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections at the end of the study period.[22]

2. Load projections
   (a) High load growth: For the filing utility's load obligation, increase the energy and demand growth rates by at least a factor of two above the base case energy or 0.5% (whichever is larger) and demand growth rates on a per customer basis. For the

[21] Staff Report in Case No. U-20633 issued, May 27, 2021 and adopted by the Commission in its September 24, 2021 order.

[22] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.

region included in the scenario utilize load growth that is consistent with the most recent MISO futures.

(b) Low load growth: EV adoption and electrification are slower than expected. Demand and load growth are consistent with 5-year historical growth rates prior to 2020 and the onset of COVID-19.

(c) 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 the demonstration year of the utility's next capacity demonstration filing. Assume that load is returned in two phases with the first half returning halfway through the 4-year forward demonstration period and the remainder returning in the demonstration year of the utility's next capacity demonstration filing. This sensitivity does not apply to utilities within an RTO that requires the incumbent utility to show capacity for choice load.

3. If the utility is not already achieving 2% EWR, ramp up the utility's EWR savings to at least 2.0% of prior year sales over the course of 3 years within the utility's Michigan jurisdiction. EWR savings remain at 2% throughout the 20-year study period.

Commented [MK3]: Again, if the inputs and assumptions used for the EWR modeling will be critically important in properly estimating the feasibility and associated costs for this sensitivity.

Scenario #2

Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario aligns with the Miso's December 2021 Futures Report, Future 3. It incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met. This scenario incorporates the retirement announcements and assumptions throughout the MISO footprint, as identified in Future 3. As subsequent Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 3 of December 2021 Futures Report may be used. Market energy purchases are modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3.

This scenario assumes significant advancements toward electrification that drives a total energy and demand annual growth rates to 1.71% and 1.41% respectively throughout the

Eastern Interconnect. Emissions decline, driven by state goals and utility plans throughout the MISO footprint, creating at least an 80% carbon reduction by 2040 from the baseline year of 2025 for the MISO region. For utilities operating in PJM, assume 80% carbon reduction by 2040 from the baseline year of 2005 for the PJM region. This trajectory of carbon reduction is expected to continue beyond 2040. Utilities should assume EV adoption reaches 50% of total vehicle sales by 2030 with a continuing trend toward 100% of vehicle sales continues throughout the study period. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change,[23] electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.

- Natural gas prices utilized are consistent with Reference Case projections from the United States energy Information Administration's (EIA) most recent annual Energy Outlook.[24]
- Current demand response, energy efficiency, and utility distributed generation programsremain in place and additional growth in those programs would happen if they were economically selected by the model to help comply with the specified carbon reductions in this scenario.
- EV adoption and customer electrification cause adjustments in overall load profiles as electrification and EV's are adopted through the planning horizon consistent with the most recent MISO Future 3.
- Specific new units are modeled if under construction or with regulatory approval (i.e., IRP cost pre-approval, CON, or signed GIA).
- For electric utilities independently administering their own EWR program, maintain a 2% EWR savings. If the utility is not already at 2%, ramp up the utility's EWR

Commented [MK4]: Again, this makes the inputs and assumptions used regarding these demand-side resources critically important. If incorrect or unnecessarily pessimistic inputs and assumptions are utilized, the modeling will select less of the EWR resource than would actually be desirable.

[23] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[24] 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.

savings to at least 2.0% of prior year sales over the course of 3 years, ~~using EWR cost supply curves provided in the 2021 supplemental potential study for more aggressive potential.~~ ~~[25]~~ EWR savings remain at 2% throughout the study period.

- Achieve and maintain a 50% renewable energy portfolio by 2030 and another 10% from other renewable resources such as voluntary green pricing and distributed generation.
- Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- All storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist. Allow for multiple market revenue streams where applicable.
- Technology costs for wind, solar, storage and other renewables decline linearly with commercial experience and forecasted at levels resulting in a 30% reduction from Scenario 1 by the end of the 20-year study period.
- Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Existing PURPA contracts are assumed to be renewed. Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.

Commented [MK5]: Again, constraining these analyses to only using the inputs and assumptions from that 2021 study is a major problem. At best, that would unreasonably increase the modeled cost of achieving that savings level, and at worst could lead to a conclusion that such savings levels were not achievable. (Recall that the 2021 Guidehouse study concluded that under their "Aggressive Scenario" the EWR potential was only an average of 1.48%.)
I strongly suggest deleting the text and footnote as shown, and just relying on the bullet point highlighted below.

Commented [MK6]: Just rely on this bullet to set the framework for estimating EWR costs and potential.

~~[25] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)~~

- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Scenario #2 Sensitivities:

1. Fuel cost projections: Increase the natural gas fuel price projections from the base projections to at leastthe high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections at the end of the study period. [26]
2. Assume all coal facilities in Michigan are retired by 2030 and Michigan electric sector meets an 80% carbon reduction from the 2005 baseline, modeled as a hard cap on the amount of carbon emissions.[27]
3. Remove the assumed RPS and assume that 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).
4. For electric utilities independently administering its own EWR program, ramp up to 2.5% EWR savings based upon prior year sales within the utility's Michigan jurisdiction.

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[26] For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.

[27] Based upon ramping to a net zero carbon power sector by 2035 https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

VIII. Michigan IRP Modeling Input Assumptions and Sources

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

	Value	Sources
1 - Analysis Period	• A minimum analysis period of 20 years, with reporting foryears 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 ifapplicable. 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 scenarioand/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 • Retirement assumptions throughout the MISO footprint are consistent with MISO futures development Future 1 and Future 3.
6 - Natural Gas Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity 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 andmade available to all intervening parties.
7 - Coal Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity 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 andmade available to all intervening parties.
8 - Fuel Oil Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity descriptions.	• If utility-specific data is utilized, it should be justified andmade available to all intervening parties.
9 - Energy Waste Reduction Savings MWhs	Base Case: • For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to loadforecast. • For non-incentive earning electric utility, mandated annualincremental savings (1.0%) as a net to load. • Not less than 35% of the state's electric needs should bemet through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3). EWR Base Case Sensitivities: • For savings beyond mandate, incorporate EWR as anoptimized generation resource. Emerging Technologies Scenario: • Ramp up EWR savings at least 2.0% over the course of four years, using EWR Cost Supply Curves provided in the2017 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 • 2021 Energy Waste Reduction Potential Study • Michigan Lower Peninsula Electric Energy Efficiency Potential Study, August, 2017 • Other pertinent studies and research as appropriate

Commented [MK7]: This study should also be listed as a source. Here is the link: https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/reports/3rdparty/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_081117.pdf?rev=eccd60040dc340b481749fd6880979d7

Commented [MK8]: Please also add this bullet, acknowledging that there might be other pertinent studies and research.

10 - Energy Waste Reduction Costs nominal dollars per kWh (Program administrator costs only; participant costs are not to beincluded in this analysis.)	• Current average levelized costs as defined in 2016/2017Potential Studies and Supplemental Modeling reflecting aggressive and cost-effective program savings goals.	• 2021 Energy Waste Reduction Potential Study • Michigan Lower Peninsula Electric Energy Efficiency Potential Study, August, 2017 • Other pertinent studies and research as appropriate
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 demandresponse as applicable to the scenario.	• As defined by 2021 Demand Response Potential Study
12 - Demand Response Costs nominal dollars per MW	• Costs/MW by program including all payments, credits, orshared savings awarded to the utility through regulatory incentive mechanism.	• As defined by 2021 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 kWhand 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, mustbe justified and made available to all intervening parties.
15 – Other Resources	• Changes to operation guides • Options which improve reliability (Storage, SVC, HVDC, CVR) • 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 wheresuch 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, other 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 tothose technologies' and options' presently unconventionalnature. 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. • Storage Resource information
16 - Wholesale Electric Prices		• Documentation for wholesale price forecast must beprovided to all intervening parties.
17 – Electric Vehicle Forecasts	Scenario 1 EIA AEO Reference Case Scenario 2 half of vehicle sales are electric by 2030	• EIA AEO Transportation

Commented [MK9]: This study should also be listed as a source. Here is the link: https://www.michigan.gov/-/media/Project/Websites/mpsc/regulatory/reports/3rdparty/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_081117.pdf?rev=eccd60040dc340b481749fd6880979d7

Commented [MK10]: Add this here as well.

IX. 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 fromthe 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 as specified in the Michigan Integrated Plan Filing Requirements.
5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled overthe 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 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 goalof 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 efficiencycost 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 Scenario 1 and Scenario 2, the utilities shall consider and prescreen all 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.

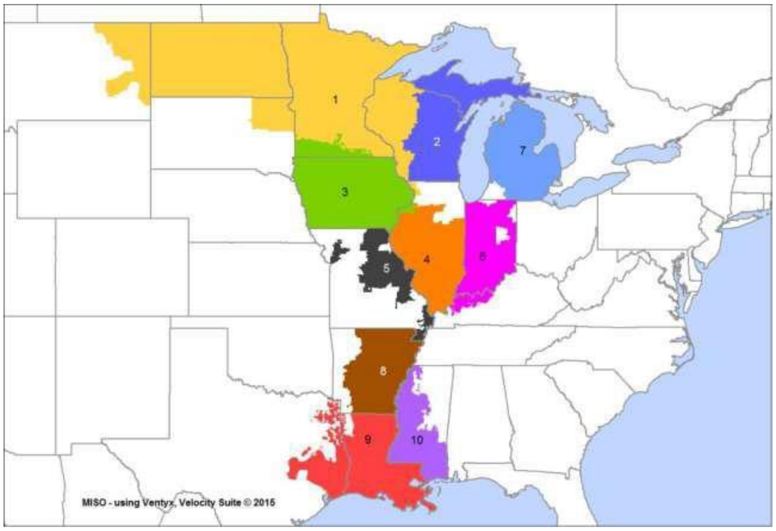
14. To the extent that the utility is proposing early retirement of a generation facility (retirement that results in an undepreciated plant balance and prior to the end of the assumed useful life), the utility should present an NPVRR analysis that compares various financing options.
15. Recognize capacity and performance characteristics of variable resources.
16. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.
17. Take into consideration existing power purchase agreements, green pricing and/or other programs.
18. 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. The utility should explicitly identify revenues that are expected to be earn that are offsets to the net present value of revenue requirements and the assumptions that those revenues are based upon.
19. An analysis regarding how incremental investments would compare to large investments in specific technologies that might be obsolete in a few years.
20. ~~19.~~ Utilities are reminded that per the *Integrated Resource Plan Filing Requirements*, stakeholder engagement early in the development of the IRP is strongly encouraged.

Commented [MK11]: It would be good to add a mention of this encouragement of stakeholder involvement in this document as well.

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

Update with Phase II and Phase III participants

Appendix B: Map of MISO Local Resource Zones



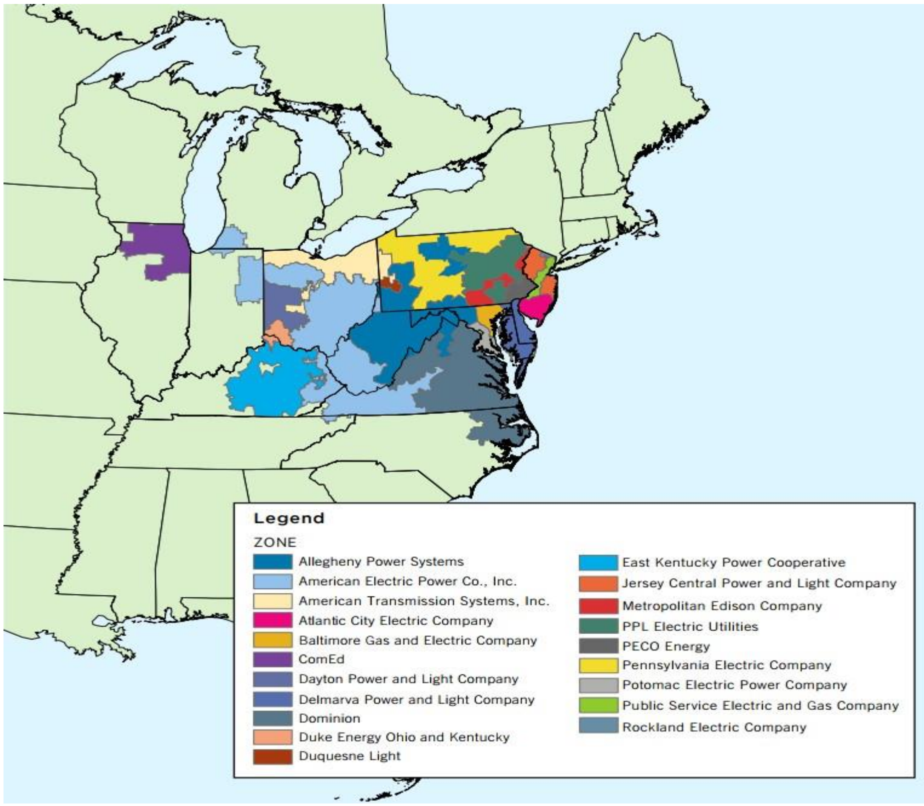
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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

MISO Zone 7 - Rate regulated electric utilities - Alpena Power Company, Consumers EnergyCompany, 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 ispart 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 the following as part of the proceeding:

(a) Conduct an assessment of the potential for energy waste reduction in this state, based on whatis 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 whatis economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already beeninstalled in this state and seek to fully maximize potential benefits to ratepayers in lowering utilitybills.

(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 additionto 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 foradditional 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 includein developing its integrated resource plan, receive written comments and hold hearings to solicitpublic input regarding the proposed modeling scenarios and assumptions.

Appendix E: Environmental Regulatory Timeline

- Updated chart forthcoming.

ENVIRONMENTAL LAW
& POLICY CENTER

May 16, 2022

I'm writing on behalf of the Ecology Center, Environmental Law & Policy Center, Union of Concerned Scientists, and Vote Solar (collectively, the CEO). We appreciate the opportunity to offer comments on Staff's draft Michigan Integrated Resource Planning Parameters. We have found the workshops thus far informative and engaging. Our collective comments are provided in narrative form below, with a few redline suggestions provided in the draft document. Please don't hesitate to reach out if you have any questions.

1. Page 27 (Discussion of Scenario 1 requirements):

   Draft: *"For all instate electric utilities participating in the State EWR Program, EWR should be based on the maximum allowed under the incentive of 1.5% and should be based on 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."*

   Comment:

   This statement should clarify whether the $/MWH cost calculated by taking the full lifetime savings and lifetime costs.

2. Page 28 (Scenario # 1 Sensitivities – Fuel cost projections) and Page 32 (Scenario # 2 Sensitivities)

   Draft: *"Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA Low Oil and Gas Supply forecast natural gas fuel price projections at the end of the study period."*

   Comment:

   See language suggestions in redline. As written, this appears to mean that the EIA forecast for each year of the planning period will be used for this sensitivity, but it is not clear based on how the requirement is written. The Footnote references the cost of natural gas in 2040 from the most recent EIA AEO which makes it unclear whether the price forecast has to converge to the 2040 price from the AEO or if the utilities should use the annual forecast from the AEO to model the gas price for this sensitivity.

3. Page 28 (Sensitivities – high and low load forecast):

   Draft: *"For the filing utility's load obligation, increase the energy and demand growth rates by at least a factor of two above the base case energy or 0.5% (whichever is larger) and demand growth rates on a per customer basis."*

“EV adoption and electrification are slower than expected. Demand and load growth are consistent with 5-year historical growth rates prior to 2020 and the onset of COVID-19.”

Comment:

It is not clear how much slower the electrification and EV adoption should be compared to the base and high forecast. What if the demand and load growth for the 5 years prior to 2020 don’t create a meaningfully low load forecast? The high forecast specifies the use of a factor or a growth rate of 0.5%. Staff might consider also specifying a growth rate for the low case. But it does seem like a wider range is needed to better capture risk of loss of load from a major customer (i.e. industrial or wholesale customer). We are skeptical that merely using 5-year historical growth rate and assuming less electrification will produce a materially low sensitivity for all utilities.

4. Page 30 (Scenario 2):

   Draft: *“Current demand response, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they were economically selected by the model to help comply with the specified carbon reductions in this scenario.”*

   Comment:

   Selection of additional EWR will be highly dependent on how the inputs are set up within the capacity expansion model. Will utilities be allowed to explore higher levels of EWR even if the resources are not optimally selected?

5. Page 31 (Scenario 2 – Battery Storage Resources):

   Draft: *“Allow for multiple market revenue streams where applicable.”*

   Comment:

   This sentence was not added to the battery storage item reported under Scenario 1. Does this mean that the market revenue streams for battery storage resources can only be applied under Scenario 2?

6. Page 33 (Modeling Input Assumptions and Sources – EWR Savings):

   Draft: *“For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to load forecast.”*

   “For savings beyond mandate, incorporate EWR as an optimized generation resource.”

   Comment:

   Similar to the comment from number 4, it may be beneficial to force in higher levels of energy efficiency since the difference in PVRR may be minimal.

7. Page 34 (Modeling Input Assumptions and Sources – EWR Costs):

Draft: *"Current average levelized costs as defined in 2016/2017 Potential Studies and Supplemental Modeling reflecting aggressive and cost-effective program savings goals."*

Comment:

Should the reference for the costs be the 2021 EWR Potential Study instead of 2016/2017? Similar to comment number 1, is the levelization calculation over the full lifetime savings and costs of the EWR programs?

8. Page 36 (Additional IRP Requirements and Assumptions):

   "*For purposes of IRP modeling, forecasted energy efficiency savings should be aggregated into hourly units, coincident with hourly load forecasts, with indicative estimates of efficiencycost 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."*

   Comment:

   It's unclear what is meant by "coincident with hourly load forecasts." We interpret this to mean that the energy efficiency savings and the load forecast should be chronologically consistent. We support this change and a clarification of this language.

   We don't think it's necessary to predict energy efficiency cost on an hourly basis – that won't influence how the resource is optimized since cost is minimized across the planning period. It is sufficient to levelize costs across the lifetime of their savings.

9. Page 37 (Additional IRP Requirements and Assumptions):

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

   Comment:

   The requirement is unclear. Is it merely to consider the time value trade-off of delaying an investment and only if there is an expectation that the technology will become obsolete in a few years? If so, we think it would be useful to provide an example of how this would apply. Typical utility investments are long-lived and don't become obsolete after only a few years.

10. General (Distributed Energy Resources):

    We strongly encourage Staff to include improved provisions for Distributed Energy Resources (DERs). The conventional utility planning approach for DERs (to the extent they account for DERs at all) is to treat them as an exogenous variable to their capacity expansion modeling. Like weather, or the economy, DER growth is something that "happens to" the utility and needs to be planned around, rather than something that the utility can affect through its own actions and can utilize to meet its customers' requirements. The conventional approach typically forecasts energy efficiency and distributed solar adoption and then subtracts them from the utility's gross load forecast to establish a net load forecast. The net load forecast is then used, either as the base case or a sensitivity, to model system expansion through large, supply-side, additions.

Instead, we propose a Distributed Generation as a Resource ("DGR") model. The DGR model applies the adoption model proposed by Eric Williams, Rexon Carvalho, Eric Hittinger, and Matthew Ronnenberg in the journal Renewable Energy in December 2019. The model relies on a robust relationship between the net present value ("NPV") cost per kilowatt for a customer to install solar and the likelihood of adoption. The Williams et. al. paper found:

> Empirical analysis for five regions (three U.S. states: Arizona, California, and Massachusetts; and two countries: Germany and Japan) from 2005 to 2016 shows a consistent relationship between annual adoption per million households and NPV.

The DGR model uses the Williams price response model to determine the cost decline for solar required to incent the next block of distributed solar uptake by customers. The model can then be utilized to predict the level of adoption of distributed generation that would result from a given incentive bundle, very similar to the approach used to estimate EWR reduction from various bundles of energy efficiency measures.

Sincerely,

Margrethe K. Kearney

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May 16, 2022

Vote Solar, the Environmental Law & Policy Center, Union of Concerned Scientists, and the Ecology Center (collectively, the Clean Energy Organizations, or "CEO") appreciate the opportunity to respond to the Staff's most recent drafts of the Michigan Integrated Resource Plan ("IRP") Filing Guidelines. Staff's proposed guidelines include important provisions requiring information about environmental justice and health impacts of integrated resource plans. The most recent iteration contains significant improvements and evidence the significant work that Staff has undertaken to conduct a deep dive into the concerns raised by stakeholders and utilities. We appreciate the time and effort that you have put into this, as well as the opportunity to provide additional comment on the most recent draft.

In September 2020, Governor Gretchen Whitmer issued Executive Directive No. 2020-10, requiring the Department of Environment, Great Lakes, and Energy EGLE to file expanded environmental advisory opinions on IRPs, including "considerations of environmental justice and health impacts." Given the Governor's directive, and the widespread impacts and benefits of IRPs in relation to public health, energy affordability, energy equity, climate change, and the environment, it is important that the Michigan Public Service Commission ("MPSC" or "Commission") address these measures in its IRP Filing Guidelines.

IRPs have the potential to both directly and indirectly impact energy equity and public health across the State of Michigan, but many of these impacts have not historically been considered in depth. We use *energy equity* to mean the inclusion of historically marginalized populations in the energy economy to create equitable, accessible, and economically beneficial policies and programs. *Environmental equity* means ensuring no populations face disproportionate pollution impacts and all populations access the benefits of clean resources and are given an opportunity to participate in the decision-making process.[1]

IRPs can either enable or hinder energy and environmental equity. As an enabler: the inclusion of resources such as energy efficiency and rooftop and community solar, or the reduction in overall expenditures on energy supply, can hold distinct implications for energy affordability, even though the exact impacts or benefits may depend in part on

[1] Krieger, Elena, *et al.* Equity-Focused Climate Strategies for New Mexico. *PSE Healthy Energy*. 2021. Available at: https://www.psehealthyenergy.org/wp-content/uploads/2021/08/Equity-Focused-Climate-Strategies_New-Mexico_Report.pdf

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decisions made in other proceedings. For example, the inclusion of sufficient demand-side energy efficiency enables these resources to be widely expanded in proceedings directly addressing low-income energy waste reduction programs. As a counter-example, the ongoing operation of an aging coal plant may produce air pollution with disproportionate impacts on nearby vulnerable or overburdened communities, which could be mitigated with the selection of alternate resources. Our key comments regarding the inclusion of environmental and energy equity measures in the IRP are as follows:

1. **The types of air pollutant emissions in the proposed IRP Filing Guidelines are reasonable.**

In order to assess public health impacts, utilities must provide information on multiple air pollutant emissions. Fine particulate matter ($PM_{2.5}$), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and volatile organic compounds (VOCs) should be reported as they are important inputs for assessing the $PM_{2.5}$-related health impacts of power plants. The $PM_{2.5}$-related health impacts are not only caused by primary $PM_{2.5}$ emissions, i.e., emissions coming directly from the stack. Instead, a large portion of the $PM_{2.5}$ health impacts occur from the secondary formation of $PM_{2.5}$ from precursors like NO_x, SO_2, and VOCs. NO_x and SO_2 have other healthy impacts not associated with $PM_{2.5}$ and NO_x and VOCs also produce ozone.

Typically, direct criteria air pollutant emissions from power plant combustion (e.g., NO_x, SO_2, and $PM_{2.5}$) are an easily quantifiable metric that can be used to evaluate the public health impacts of power sector resources, because most flue stacks are equipped with Continuous Emissions Monitoring Systems or reporting is required for other purposes.

2. **The proposed IRP Filing Guidelines should require information on both *total* emissions and the *rate of* emissions.**

It is useful to evaluate both the *total* emissions from any facility as well as the *rate* of emissions, per megawatt-hour of generation, from each facility. The total emissions can give a sense of which power plant has the greatest total impact, and if multiple scenarios are presented within an IRP, the sum of emissions across different scenarios can be a useful tool. The *rate* of emissions is also a useful comparison tool to illustrate where the reduction of a megawatt-hour of generation from across the resource portfolio would have the greatest reduction in pollutant emissions. For example, one megawatt-hour of solar generation will help reduce more criteria pollutant emissions if it displaces one megawatt-hour of electricity from a plant with a higher emission rate than a lower emission rate. A comparison of the rate of emissions from each plant in the fleet, averaged over a single or multiple historic years, can indicate whether strategies such as shifting electricity generation requirements between plants or retiring specific power plants would help maximize emission reductions.

3. **The IRP Filing Guidelines should include information about air pollutants and associated health impacts even if there is no increase in emissions.**

Even if emissions are not expected to increase as a result of a proposed plan, that does not mean that the power plants included in the plan are not contributing to environmental justice impacts. Simply because a plant has been polluting a community for years already should not give it license to continue to pollute that area. Any ongoing operation could continue to exacerbate the inequitable impacts of existing facilities.

Geographically-specific modeling of air pollutant emission impacts can provide spatially detailed data on total and per-capita health impacts, including where plants may have a disproportionate impact on specific populations, providing better data on the environmental justice impacts of these facilities—and potential strategies to mitigate these emissions.There should also be a discussion about how historic cumulative environmental burdens from power plants are included within the decision-making process.

4. **The IRP Filing Guidelines properly include information about the spatial distribution of power plant public health impacts.**

In addition to total health impacts, it is valuable to calculate the *spatial distribution* of power plant public health impacts, both in total and on a per-capita basis. This spatial distribution can provide insight into the demographics of the populations that may be disproportionately impacted by pollution from one or more facilities in the utility's portfolio, informing which communities might particularly benefit from pollution reduction. These analyses can also provide information on the demographics of populations facing a disproportionate share of health impacts per capita from a given power plant's emissions. IRPs can incorporate these data on cumulative and disproportionate health impacts to inform resource selection that will reduce these impacts on particularly overburdened or vulnerable populations. The filed IRP should include an explanation about how these analyses affected decision-making. In addition, while air pollutant impacts tend to be highest, per capita, on populations living near and downwind from a source, it is not straightforward to model the health impacts of all pollutant emissions, due to both limited data availability for all pollutants and more complicated modeling requirements for certain pollutants.

We also support the inclusion of proximity analysis, and find the 3-mile radius for EJ communities and 6-mile radius for calculating disproportionate health impacts reasonable.

5. **The models proposed in the IRP Filing Guidelines are reasonable.**

The health impacts of $PM_{2.5}$, either through direct emission of fine particulate matter or secondary formation from reactions of precursors such as NO_x, SO_2, and VOCs in the atmosphere, can be modeled using reduced-form modeling tools such as the EPA's COBRA or BenMAP or the peer-reviewed InMAP model. These tools can be used to estimate the impacts of emissions from a point source on ambient $PM_{2.5}$ and the subsequent $PM_{2.5}$-related health impacts associated with the changes in ambient $PM_{2.5}$ based on epidemiological models. Plants located in or upwind from dense population areas are likely to have higher total impacts than those in rural areas, but per-capita impacts are highest close to and downwind from the emission source, no matter the population density. Much like for emissions, there can be a value in calculating the total health impacts of a given power plant or a given scenario as well as the rate of health impacts per megawatt-hour or gigawatt-hour of generation.

Sincerely,

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MICHIGAN INTEGRATED RESOURCE PLANNING PARAMETERS

Pursuant to Public Act 341 of 2016, Section 6t

Draft 2022

Table of Contents

I. Executive Summary

This Michigan Integrated Resource Planning Parameters document was developed as a partof the implementation of the provisions of Public Act 341 of 2016 (PA 341), Section 6t. This document includes two integrated resource plan (IRP) modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Upper and Lower Peninsulas. 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 beviewed 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 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 and Energy Waste Reduction Potential Studies were completed August of 2021. Both studieshave an influence on integrated resource planning and are

incorporated into the Commission's Docket (Case No. U-21219[1]) for the 5-year update pursuant to 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. This is the first 5-year update. The next 120-day proceeding to conduct these assessments and gather input shouldcommence in July 2027.

II. Background

On December 21, 2016, PA 341 was signed 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 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 MPSCfor review and approval.

At the conclusion of a stakeholder process and issuance of draft Michigan Integrated Resource Planning Parameters (MIRPP), the Commission adopted the MIRPP on November 21, 2017, in Case No. U-18418.

Pursuant to PA 341, the MPSC and the Department of Environment, Great Lakes and Energy (EGLE) began a second collaborative process as part of MI Power Grid Phase II – Integration of Resource/Distribution/Transmission Planning on September 24, 2020, with state-wide participation from a wide-range of stakeholders (listed in Appendix A). On October 29, 2020, the Commission issued an order in Case No. U-20633 directing Staff to also work with stakeholder groups to determine how to update IRP planning parameters and filing requirement to take into account the goals set by Michigan's utilities and how

[1] Add link once we have a docket.

these goals align with the greenhouse gas emissions targets set by Governor Whitmer. Stakeholder sessions discussed many aspects of PA 341 Section 6t including:

i. Environmental Policy
ii. Forecasting
iii. Transmission
iv. The Regional Energy Market
v. Distributed Energy Resources
vi. Economic valuation
vii. Generation Diversity
viii. Risk Assessment

Stakeholders were invited to participate by providing comments and feedback during and after every stakeholder session. met regularly from December 2021 to late April 2022 to discuss how to update various subsections of PA 341 Section 6t. Further details on the stakeholder sessions are included on the MPSC's web page for Phase III of the MI Power Grid initiative.[2]

The Commission released an earlier draft of this document with a Commission Order initiating Case No. U-21219 on July, 2022. Interested parties were provided an opportunity to file comments and reply comments in Case No. U-21219. The Commission has considered the comments and reply comments and has incorporated several changes herein.

III. 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 conducted by Guidehouse Inc. (Guidehouse) for electricity and natural gas for the entire State of

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[2] https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93320-508709--,00.html.

Michigan. This study's objective was to assess the potential in the residential, commercial, and industrial sectors, with the addition of small commercial, multifamily, and low-income segments, by analyzing EWR measures and improvements to end-user behaviors to reduce energy consumption. Measure and market characterization data was input into Guidehouse's Demand Side Management Simulator (DSMSim™) model, which calculates technical, economic, and achievable potential across utility service areas in Michigan for more than 600 measure permutations. Results were developed and are presented separately for the Lower and Upper Peninsulas. These results will be used to inform EWR goal setting and associated program design for the MPSC.[3]

Scenario #1: Reference–Estimates of achievable potential calibrated to 2021 total program expectations and refined using relative savings percentages at the end use and high impact measure-level with 2019 actual achievements. Key assumptions include non-low-income measure incentives of 40% of incremental cost (low-income segments incentivized at 100% of incremental cost) and administrative costs representing 33% of total utility program spending.

Scenario #2: Aggressive–Increased measure incentives and marketing factors and decreased program administrative costs. Analyzed measure incentive levels to determine the 1.0 Utility Cost Test (UCT) ratio tipping point. Developed measure-level incentive estimates based on these results and adjusted where necessary to ensure program-level cost effectiveness. Increased marketing factors above calibrated values for specific end use and sector combinations.

Scenario #3: Carbon Price–Acknowledging the regulatory uncertainty around carbon price legislation, provides a high-level fuel cost adder, ramping up through time as the probability of regulatory action increases. This scenario provides insight into the sensitivity of EWR savings potential to avoided costs. Due to the uncertain nature of carbon pricing legislation, the scenario is not related to specific program or policy recommendations.

[3] MI EWR Potential Study MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov), Retrieved December 8, 2021.

Increased electricity ($/MWh) and natural gas ($/therm) avoided costs by 50% in 2021, escalating with a 2.5% multiplier growth until a 100% increase was met.

IV. Demand Response Potential Study[4]

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

The MPSC issued a request for proposal for the DR potential study in May of 2020. Bids were received and evaluated and a contract for the study was awarded to Guidehouse Inc. in August of 2020. The DR potential study assessed DR potential in Michigan from 2021 to 2040 and was conducted in conjunction with the energy waste reduction (EWR) potential study. The DR potential study was completed in September of 2021.

The objective of the DR potential assessment was to estimate the potential for cost-effective DR as a capacity resource to reduce customer loads during peak summer periods. Additionally, the study assessed electric winter peak reduction potential and natural gas DR potential. DR potential estimates were developed for both the Lower Peninsula and the Upper Peninsula.

The DR potential and cost estimates were developed using a bottom-up analysis. The analysis used customer and load data from Michigan utilities for market characterization, customer survey data to assess technology saturation and customer willingness to enroll in DR programs, DR program information from Michigan utilities, the latest available information from the industry on DR resource performance and costs. These sources provided input data to the model used to calculate total DR potential across Michigan.

The DR potential study was a collaborative process wherein the MPSC, Guidehouse, and stakeholders worked together to ensure the study reflected current Michigan market trends. Three virtual stakeholder meetings were held during the study which provided

[4] 2021 Energy Waste Reduction and Demand Response Statewide Potential Study, https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/demand-response-potential-study/

stakeholders with an update on study progress and an opportunity to provide feedback to Guidehouse and MPSC Staff.

V. State and Federal Environmental Regulations, Laws and Rules

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

Section 460.6t (1) (c)

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 (USEPA) to set NAAQS for six criteria pollutants that havethe potential of harming human health or the environment. The NAAQS are rigorously vetted bythe scientific community, industry, public interest groups, and the public. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standardsare set at a level that is protective of human 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 everyfive years by the Clean Air Scientific Advisory Committee. The six criteria pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.[5]

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

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 notabide by the Clean Air Act requirements to reign in the emissions of the pollutants are subject toUSEPA 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 USEPA for approval into the State Implementation Plan (SIP), and ensuring attainment occurs bythe 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 USEPA strengthened the primary NAAQSfor SO_2, establishing a new 1-hour standard of 75 parts per billion (ppb).

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

In May 2016, Michigan Department of Environment, Great Lakes, and Energy (EGLE) submitted its SO2 State Implementation Plan (SIP) strategy for southern Wayne County to the USEPA for final approval. This SIP was the strategy for bringing the area into compliance with the health-based NAAQS for SO2. Due to a lawsuit related to a portion of the SIP, USEPA is pursuing a federal implementation plan (FIP) for the non-attainment area, the action of which is still underway. In January 2022, USEPA made the formal determination that southern Wayne County did not attain the SO2 NAAQS by the 2018 deadline.

USEPA is working to complete the FIP and expects that it will be available for public comment sometime in winter of 2022. Following the approval of the FIP, EGLE will work

to incorporate its provisions into the SO2 SIP. Once all of the elements of the SIP have been implemented, EGLE plans to pursue a redesignation request for southern Wayne County.

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.

To better understand the quality of the air in the non-attainment area, tow monitors were installed in the vicinity in November 2016. The monitoring data has consistently shown SO2 levels in the area to be below the SO2 NAAQS. The Clean Air Act allows a state to submit a Clean Data Determination (CDD) to the USEPA if air monitors show three consecutive years of attaining data in a non-attainment area. This action waives the requirement for the state to produce a SIP for the non-attainment area.

EGLE determined that the CDD criteria had been met for the St. Clair non-attainment area and submitted a CDD to USEPA in July 2020, waiving the SIP requirement for the area. EGLE's CDD was approved by USEPA in December 2021. Upon shutdown of the St. Clair Power Plant in May 2022, EGLE expects to submit a redesignation request to USEPA for the St. Clair County non-attainment area as well.

Round three designations were to address all remaining undesignated areas by December 31, 2017. The USEPA 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 USEPA 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, were also designated as unclassifiable/attainment.

Ozone Non-Attainment Areas: In 2015, the USEPA strengthened the primary NAAQS for ozone, establishing a new 8-hour standard of 70 ppb.

On August 3, 2018, Michigan was designated marginal non-attainment for the 2015 ozone NAAQS in four areas (ten counties) of the state. In southeast Michigan, the seven-county area encompassing Livingston, Macomb, Monroe, Oakland, St. Clair, Washtenaw, and Wayne counties and on the west-side, two partial counties including Allegan and Muskegon and one full county, Berrien were found to have design values[6] exceeding the new ozone NAAQS of 70 ppb. This classification established an attainment deadline and attainment plan submittal date of August 3, 2021. In addition to the requirement to attain by this deadline, there are also 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 attain the standard, monitoring values over the three-year period between 2018 and 2020 must have design values at or below the standard of 70 ppb.

In the fall of 2021, EGLE began working on a redesignation request for the seven-county southeast Michigan nonattainment area. Although design values for the three-year period between 2018 and 2020 did not show attainment with the 2015 ozone NAAQS, the design values for the three-year period between 2019 and 2021 did attain. The redesignation request was submitted to USEPA in January 2022, and approval is expected in late spring/early summer 2022. The three western non-attainment counties (partial Muskegon and Allegan and full county Berrien) did not attain the standard. It is expected that USEPA will reclassify or “bump up” those counties from marginal to moderate non-attainment. A reclassification from marginal to moderate extends the attainment deadline to August 2024; however, a classification of moderate requires additional actions to reduce emissions to attain the standard. Required moderate nonattainment planning elements include (but are not limited to) major source reasonably available control technology, 15% reasonable further progress, and an attainment demonstration.

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

[6] The design value is the three-year average of the 4th highest 8-hour ozone value)

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 governsthe 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 (April through October). 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. The USEPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May 2017. The state currently has Good Neighbor obligations for the 2015 ozone standard.

On March 15, 2021, USEPA finalized the revised CSAPR rule update for the 2008 ozone NAAQS. Starting with the 2021 ozone season, the revised rule reduced the emission budgets and therefore allocation of NOx allowances from power plants in 12 states, including Michigan. The revision includes adjusting these 12 states emissions budgets for each ozone season from 2021 through 2024.

EPA establishes that the revised CSAPR update will reduce NO_x emissions from power plants in 12 states in the eastern United States by 17,000 tons in 2021 compared to projections without the rule, yielding public health and climate benefits that are valued, on average, at up to $2.8 billion each year from 2021 to 2040.

Mercury and Air Toxics Standards – Section 302 of the Clean Air Act requires the USEPA 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 EGLE. In June 2015, the United States Supreme Court found that the USEPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the District of Columbia Circuit Court of

Appeals ruled that MATS may be enforced as the USEPA modifies the rule to comply with the United States Supreme Court decision. The deadline for MATS compliance forall electric generating units was April 16, 2016.

In December 2015, in response to the United States Supreme Court's direction, the USEPA published a proposed supplemental finding that a consideration of cost does not alter their previous determination that it is appropriate and necessary to regulate air toxic emissions from coal- and oil-fired EGUs. The proposed supplemental finding was based on an evaluation of several cost metrics relevant to the power sector and also considered public comments. USEPA found that the cost of compliance with MATS was reasonable and that the electric power industry could comply with MATS and maintain its ability to provide reliable electric power to consumers at a reasonable cost. USEPA's supplemental cost finding was finalized in April 2016.

In May 2020, USEPA completed a reconsideration of the April 2016 appropriate and necessary finding for the MATS, correcting flaws in the approach considering costs and benefits while ensuring that HAP emissions from power plants continue to be appropriately controlled. The agency also completed the CAA required residual risk and technology review for MATS. Following that reconsideration, USEPA concluded that the consideration of cost in the 2016 Supplemental Finding was flawed. Specifically, they found that what was described in the 2016 Supplemental Finding as the preferred approach, or "cost reasonableness test," did not meet the statute's requirements to fully consider costs and was an unreasonable interpretation of the CAA mandate. Power plants were already complying with the standards limiting emissions of mercury and other HAPs, and that final action leaves those emission limits in place and unchanged.

In January 2022 USEPA issued a proposal to reaffirm that it remains appropriate and necessary to regulate HAPs, including mercury, from power plants after considering cost. This action revokes the May 2020 finding that it was not appropriate and necessary to regulate coal- and oil-fired power plants under CAA Section 112 which covers toxic air pollutants. USEPA reviewed the 2020 finding and considered updated information on both the public health burden associated with HAP emissions from coal- and oil-fired power plants as well as the costs associated with reducing those emissions under the

MATS. After weighing the public risks posed by these emissions to particularly exposed and sensitive populations, against the costs of reducing HAP emissions, USEPA is proposing to conclude that it remains appropriate and necessary to regulate these emissions.

CAA 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 CAA for certain industrial sources of emissions determined to endanger public health and welfare. In October 2015, the USEPA 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.[7]

CAA Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources - Electric Utility Generating Units (Clean Power Plan) – Section 111(d) of the CAA requires the USEPA to establish standards for certain existing industrial sources. The final Clean Power Plan (CPP), promulgated on October 23, 2015, addressed carbon dioxide emissions from EGUs. The CPP 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.[8]

On February 9, 2016, the United States Supreme Court issued five orders granting a stay ofthe Clean Power Plan pending judicial review. On March 28, 2017, President Trump signed anExecutive Order directing the USEPA 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

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[7] 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.

[8] 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.

cases in abeyance pending the USEPA's review of both rules, including through the conclusion of any rulemaking process thatresults from that review.

On June 19, 2016, the USEPA promulgated the Affordable Clean Energy (ACE) Rule which replaced and repealed the Clean Power Plan. The ACE rule established emission guidelines for states to use in developing plans to limit carbon emissions at their coal-fired electric generating units (EGU); but did not establish specific carbon emission reduction goals. The ACE rule focused on an "inside the fence line" best system of emission reduction approach to emission reductions in the form of heat rate improvements at each EGU. On January 19, 2021, the United States Court of Appeals for the District of Columbia Circuit vacated the ACE rule and remanded it back to the USEPA for further proceedings consistent with the Court's ruling. On October 29, 2021, the United States Supreme Court agreed to grant a writ of certiorari for petitions for review of the January 2021 decision of the United States Court of Appeals for the District of Columbia Circuit to strike down USEPA's 2019 ACE Rule. Four pending petitions before the United States Supreme Court were filed earlier in 2021 by a coalition of nineteen states led by West Virginia, the State of North Dakota, the North American Coal Corporation, and Westmoreland Mining Holdings, LLC. The Supreme Court is expected to hear the four combined cases in its current term with a ruling expected in late spring or early summer 202~~1~~2.

Although there are not currently any rules regulating carbon emissions from existing Electric Generating Units (EGU); due to the USEPA's 2009 endangerment finding on greenhouse gasses, and in light of the current reduction goals on carbon neutrality at both state and federal levels, utilities should address their anticipated greenhouse gas emissions with those carbon neutrality reduction goals in mind.

Greenhouse Gas Reporting Program – The Greenhouse Gas Reporting Program (codifiedat 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 USEPA. Annual reports covering emissions from the prior calendar year are due by March 31 of each year. The USEPA 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 standardsfor 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 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 improvevisibility, 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 timeto 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, andammonia. 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 eachsource-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 thatmay 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 USEPA. In 2005, the USEPA published the guidelines for BART determinations. Michigan has met the initial BART determination requirements. In December 2016, the USEPA issued a final rule setting revised and clarifying requirements for periodic updatesin state plans. The next periodic update was due July 31, 2021. EGLE

has submitted the periodic update and it is currently being reviewed by USEPA. 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 **US**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 USEPA established requirements for the safe disposal of coal combustion residuals (CCR) produced at electric utilities and independent power producers. These requirements were established under Subtitle D of RCRA and apply to coal combustion residual landfills andsurface impoundments. Michigan electric utilities must comply with these regulations.

In July 2016, the USEPA Administrator signed a direct final rule and a companion proposal to extend for certain inactive CCR surface impoundments the compliance deadlines established by the regulations for the disposal of CCR under Subtitle D (Non-hazardous solid waste). These revisions were completed in response to a partial vacatur ordered by the United States Court of Appeals for the District of Columbia Circuit on June 14, 2016. This direct final rule became effective on October 4, 2016.

In July 2018, the USEPA finalized certain revisions to the 2015 regulations for the disposal of CCR in landfills and surface impoundments to provide states with approved CCR permit programs under the Water Infrastructure Improvements for the Nation (WIIN) Act or USEPA (where USEPA is the permitting authority) the ability to use alternate performance standards and to revise the groundwater protection standards for four constituents in Appendix IV to part 257 for which maximum contaminant levels (MCLs) under the Safe Drinking Water Act had not been established. The revision also provided facilities which are triggered into closure by the regulations additional time to cease receiving waste and initiate closure. This additional time was meant to better align the CCR rule compliance

dates with the Effluent Limitations Guidelines and Standards Rule for the Steam Electric Power Generating Point Source Category.

In September 2020, the USEPA finalized amendments to the part 257 regulations. First, the USEPA finalized a change to the classification of compacted-soil lined or “clay-lined” surface impoundments from “lined” to “unlined” under § 257.71(a)(1)(i), which reflected the vacatur ordered in the Utility Solid Waste Activities Group (USWAG) decision. Secondly, USEPA finalized revisions to the initiation of closure deadlines for unlined CCR surface impoundments, and for units that failed the aquifer location restriction, found in §§ 257.101(a) and (b)(1). These revisions addressed the USWAG decisions with respect to all unlined and “clay-lined” impoundments, as well as revisions to the provisions that were remanded to the Agency for further reconsideration. Specifically, USEPA finalized a new deadline of April 11, 2021, for CCR units to cease receipt of waste and initiate closure because the unit was either an unlined or formerly “clay-lined” CCR surface impoundment (§ 257.101(a)) or failed the aquifer location standard (§ 257.101(b)(1)). With this action, USEPA also finalized revisions to the alternative closure provisions, § 257.103. The revisions granted facilities additional time to develop alternative capacity to manage their waste streams (both CCR and/or non-CCR), to achieve cease receipt of waste and initiate closure of their CCR surface impoundments.

In November 2020, the USEPA published the CCR Part B final rule which allowed a limited number of facilities to demonstrate to USEPA or a participating state director that, based on groundwater data and the design of a particular surface impoundment, the unit had and will continue to ensure there is no reasonable probability of adverse effects to human health and the environment. The regulations stated that facilities had until November 30, 2020 to submit applications to USEPA for approval, but given the effective date for the final rule was December 14, 2020, USEPA accepted revisions or applications until December 14, 2020.

In October 2020, USEPA issued an advanced notice of proposed rulemaking seeking input on inactive surface impoundments at inactive electric utilities, referred to as "legacy CCR surface impoundments". The information and data received will assist in the development of future regulations for these CCR units.

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 USEPA promulgated rules under Section 316(b) of theClean 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 USEPA 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 aclosed-cycle, recirculating cooling system.

Following a previously promulgated version of the rules and judicial remand, the regulationsfor 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. Therules do not specify national BTA standards for minimizing entrainment mortality, but instead require that EGLE establish the BTA entrainment requirements for a facility on a site-specificbasis. 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 mustprovide 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, facilitieswill need to achieve the impingement and entrainment mortality standards as soon as practicableaccording to the schedule of requirements set by EGLE 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 (ELG) 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 reviewchallenging the regulations were consolidated in the United States Court of Appeals for the FifthCircuit on December 8, 2015. On April 25, 2017, the USEPA issued an administrative stay of the compliance dates in the ELGs and standards rule that had not yet passed pending judicial review. In addition, the USEPA requested, and was granted, a 120-day stay of the litigation (until September 12, 2017) to allow the USEPA to consider the merits of the petitions for reconsideration of the Rule. On August 11, 2017, the USEPA provided notice that it would conduct a rulemaking to revise the new, more stringent BTA effluent limitations and Pretreatment Standards for Existing Sources in the 2015 rule that apply to bottom ash (BA) transport water and flue gas desulfurization wastewater (FGD). The EPA published the regulations on October 13, 2020, finalizing the revisions for these two wastewaters allowing for less costly technologies, a two-year extension of the compliance time frame and for meeting the requirements, and adding subcategories for both wastewaters. The subcategories included a voluntary incentive program for more restrictive limitations for FGD wastewaters with a longer compliance schedule, and an allowance that electric generating units that decommission by December 31, 2028, need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities. The earliest date for compliance with bottom ash and FGD wastewaters was set for October 13, 2021, but no later than December 31, 2025, unless the facility announces compliance with an optional program. In addition, the EPA published an announcement on August 3, 2021, on its decision to undertake additional rulemaking to again revise the SEEG. As part of the rulemaking process, the EPA will determine whether more stringent effluent limitations and standards are appropriate and consistent with the technology-forcing statutory scheme and the goals of the Clean Water Act. EPA intends to publish the proposed rulemaking for public comment in the fall of 2022. On September 18, 2017, the 120-day administrative stay was lifted postponing certain compliance deadlines. The earliest date for compliance with SEEG was November 1, 2020.

On August 31, 2020, USEPA finalized a rule revising the regulations for the Steam Electric Power Generating category (40 CFR Part 423). The rule revises requirements for two specific waste streams produced by steam electric power plants: FGD wastewater and BA transport water. In the revised rule, USEPA delays the compliance deadlines for BA transport water and FGD wastewater two years to December 31, 2025. In addition, the revised rule includes a voluntary incentive program that provides additional time, until December 31, 2028, for facilities that implement additional processes that achieve more stringent limitations and also has an allowance that electric generating units that decommission by December 31, 2028 need not comply with the more costly and restrictive requirements of the 2015 ELGs based upon a cost evaluation which takes into consideration the remaining useful lifespan of these facilities.

State Rules and Laws:

The majority of Michigan's environmental regulations/laws/acts were consolidated into the Natural Resources and Environmental Protection Act (NREPA) of 1994, Public Act 451 as amended (Act 451). Act 451 is organized into sections called "Parts" and serves "to protect the environment and natural resources of the state; to codify, revise, consolidate, and classify laws relating to the environment and natural resources of the state; to regulate the discharge of certain substances into the environment; to regulate the use of certain lands, waters, and other natural resources of the state; to protect the people's right to hunt and fish; to prescribe the powers and duties of certain state and local agencies and officials; to provide for certain charges, fees, assessments, and donations; to provide certain appropriations; to prescribe penalties and provide remedies; and to repeal acts and parts of acts."

Michigan Mercury Rule – The purpose of the Michigan Mercury Rule (MMR) is to regulatethe 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 CCR as a solid waste. It requires any CCR that will remain in place in asurface impoundment or landfill be subject to siting criteria, permitting and licensing of the disposal area, construction standards for the disposal area, groundwater monitoring, correctiveaction, and financial assurance and post-closure care for a 30-year period. The disposal facilityis required to maintain the financial assurance to conduct groundwater monitoring throughout the post-closure care 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 InfrastructureImprovements 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. Under the amendment, 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. In 2018, Part 115 was amended to include the majority of the RCRA regulations would be enforced by states and the CCR units would not be subject to the dual regulatory structure. In 2018, Part 115 was amended to include the majority of the RCRA rule, including the regulation of CCR surface impoundments used for

storage. Michigan's request for state program approval is currently under review by the USEPA.

To comply with PA 341 Section 6t (5) (m)
"How the utility will comply with all applicable state and federal environmental regulations, lawsand 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 ofcompliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's 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 theMichigan 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.

VI. 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 reservemargins 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 intolocal resource zones (Zones) with the majority of the Lower Peninsula in Zone 7 and the UpperPeninsula combined with a large portion of Wisconsin in Zone 2, as shown in Appendix B. Theunshaded 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.[9] The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, "MISO System Planning Reserve Margins 2022 through 2031" for the entire footprint.[10] MISO also calculates the local reliability requirement of each Zone in the LOLE Study Report.[11] 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 the LOLE requirement while fully using the Capacity Import Limit for such."[12] The Local ClearingRequirement for each zone is reported annually with the MISO planning resource auction resultsin April.[13]

For the southwest corner of the Lower Peninsula, in PJM's territory,[14] similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.[15] PJM outlines requirements for an Installed Reserve Margin, similar to MISO's planning reserve margin on aninstalled capacity basis, and a Forecast Pool Requirement on an unforced capacity basis, similarto MISO's planning reserve margin on an unforced capacity basis. PJM also specifies 27 LocalDeliverability Areas somewhat similar to MISO's local resource zones.

[9] MISO 2022-2023 Loss of Load Expectation Study Report published on November 1, 2021

https://cdn.misoenergy.org/PY%202022-23%20LOLE%20Study%20Report601325.pdf.

[10] 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.

[11] 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.

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

[13] MISO Planning Resource Auction results, April 2021

https://cdn.misoenergy.org/PY21-22%20Planning%20Resource%20Auction%20Results541166.pdf

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

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

PJM publishes a Reserve Requirement Study [16] annually in October containing the requirements for generator owners andload 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 capacitydemonstration 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 through2021. 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, toestablish 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 utilityIRP filings should be consistent with the requirements of the State Reliability Mechanism underSection 6w, as established in Case Nos. U-18197, U-18444, and any subsequent cases initiated to implement these provisions.

VII. 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, twomodeling scenarios are required. Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other

[16] PJM Reserve Requirement Study, October 2021.

https://www.pjm.com/-/media/committees-groups/subcommittees/raas/2021/20211004/20211004-pjm-reserve-requirement-study.ashx

jurisdictions. Due to the provisions in PA 341Section 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

(Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario directionally aligns with MISO's December 2021 Futures Report, Future 1 and reflects substantial achievement of state and utility announcements including generation retirements and environmental goals. This scenario incorporates 100% of utility integrated resource plan (IRP) retirement announcements and retirement assumptions throughout the MISO footprint, as identified in MISO Future 1. For the utility performing the analysis, the generation unit retirement assumptions may vary for only the generation units the utility has decision making authority. As subsequent MISO Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 1 of the December 2021 report may be used. This scenario assumes that CO2 emissions decline, driven by state goals and utility plans throughout the MISO footprint creating at least a 63% carbon reduction by 2040 from the baseline year of 2005 for the MISO region. This trajectory of carbon reduction is expected to continue beyond 2040.

This scenario assumes that demand and energy growth are driven by existing economic factors, with moderate electric vehicle (EV) adoption and customer electrification, resulting in moderate MISO footprint wide demand and energy growth rates. Utilities should use the most recent United States Energy Information Administration (EIA) Annual

Energy Outlook (AEO) Reference Case[17] or other reputable source for forecasted EV adoption rates. If the utility does not use EIA AEO then the EV forecast information must be provided within the utility IRP filing. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change, [18] electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.

*Note: Scenario aligns with MISO Future 1 from the December 2021 MISO Futures Report. If, in the future, MISO Futures significantly change, regulated utilities will work with Staff to determine the most appropriate future to use for Scenario 1.

- Natural gas prices utilized are consistent with the Reference Case projections from the United States Energy Information Administration's (EIA) most recent Annual Energy Outlook.[19]
- Moderate EV adoption and customer electrification result in moderate footprint-wide demand and energy growth. Within Michigan, EV and electrification forecasts should be blended with historical sales such that after 3 years, Michigan's load and demand increase reflects the source forecasts for EV and electrification technologies. Load profiles of EVs and electrification technologies should be clearly delineated and presented individually such that it is clear how they each impacted the overall energy and demand forecast. EV forecasts should be based off the Reference Case in the most recent EIA AEO. Electrification technology

[17] Electric Vehicle adoption as forecasted in the most recent EIA AEO East North Central Census Region Reference Case, http://www.eia.gov/outlooks/aeo/tables_ref.php

[18] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[19] 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 include delivery costs from Henry Hub to the point of delivery.

forecasts should be based off of either established proprietary forecasts or publicly available data.

- Resource assumptions: Assume MISO Future 1 retirements for existing thermal and nuclear generation resources published in the most recent Futures Report should be used when available along with recent public announcements. Specific new units will be modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON), IRP cost pre-approval, or signed generator interconnection agreement (GIA). Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO) should also be used. Generic new resources are assumed consistent with the scenario description, considering anticipated new resources currently in generation interconnection queue, and should be chosen based upon economics.
- 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 participating in the State EWR Program, 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.[20]
- Existing renewable energy and storage production tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- All storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist.[21] Allow for multiple market revenue streams where applicable.
- Technology costs for thermal units and wind track with mid-range industry expectations.

Commented [CH1]: Language was added for Scenario 2. Does it also apply for Scenario 1?

[20] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)

[21] Staff Report in Case No. U-20633 issued, May 27, 2021 and adopted by the Commission in its September 24, 2021 order.

- Technology costs and limits to the total resource amount available for EWR and demandresponse programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Technology costs for solar, storage, and other emerging technologies decline with commercial experience consistent with NREL or other publicly available reputable sources.
- Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Scenario #1 Sensitivities:

1. Fuel cost projections

(a) Increase the natural gas fuel price projections from the base projections to at least the high EIA gas price in the most recent EIA ~~Low~~ Oil and Gas Supply forecast. ~~natural gas fuel price projections at the end of the study period.~~[22]

2. Load projections

(a) High load growth: For the filing utility's load obligation, increase the energy and demand growth rates by at least a factor of two above the base case energy or 0.5% (whichever is larger) and demand growth rates on a per customer basis. For the region included in the scenario utilize load growth that is consistent with the most recent MISO futures.

(b) Low load growth: EV adoption and electrification are slower than expected. Demand and load growth are consistent with 5-year historical growth rates prior to 2020 and the onset of COVID-19.

Commented [MKK2]: See written comments provided with redline.

[22] ~~For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is \$8.41/MMBtu (\$2019) in 2040.~~

(c) 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 the demonstration year of the utility's next capacity demonstration filing. Assume that load is returned in two phases with the first half returning halfway through the 4-year forward demonstration period and the remainder returning in the demonstration year of the utility's next capacity demonstration filing. This sensitivity does not apply to utilities within an RTO that requires the incumbent utility to show capacity for choice load.

3. If the utility is not already achieving 2% EWR, ramp up the utility's EWR savings to at least 2.0% of prior year sales over the course of 3 years within the utility's Michigan jurisdiction. EWR savings remain at 2% throughout the 20-year study period.

Scenario #2

Applicability: Utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, encouraged for multi-state utilities.)

This scenario aligns with the Miso's December 2021 Futures Report, Future 3. It incorporates 100% of utility IRPs and announced state and utility goals within their respective timelines and assumes that 100% of the utility and state goals are met. This scenario incorporates the retirement announcements and assumptions throughout the MISO footprint, as identified in Future 3. As subsequent Futures Reports are released, updated retirement assumptions identified in the Future most similar to Future 3 of December 2021 Futures Report may be used. Market energy purchases are modeled at a carbon intensity consistent with the relevant RTO system average. MISO expected system averages are identified in Future 3.

This scenario assumes significant advancements toward electrification that drives a total energy and demand annual growth rates to 1.71% and 1.41% respectively throughout the Eastern Interconnect. Emissions decline, driven by state goals and utility plans throughout the MISO footprint, creating at least an 80% carbon reduction by 2040 from the baseline year of 2025 for the MISO region. For utilities operating in PJM, assume 80% carbon reduction by 2040 from the baseline year of 2005 for the PJM region. This trajectory of carbon reduction is expected to continue beyond 2040. Utilities should assume EV adoption reaches 50% of total vehicle sales by 2030 with a continuing trend toward 100% of vehicle sales continues throughout the study period. Using this information, utilities may develop their own demand and energy forecasts with description and detail how their forecast has included the impacts of climate change,[23] electrification, demand side resources, and customer owned distributed generation and how these factors change overall load and demand.

- Natural gas prices utilized are consistent with Reference Case projections from the United States energy Information Administration's (EIA) most recent annual Energy Outlook.[24]
- Current demand response, energy efficiency, and utility distributed generation programsremain in place and additional growth in those programs would happen if they were economically selected by the model to help comply with the specified carbon reductions in this scenario.
- EV adoption and customer electrification cause adjustments in overall load profiles as electrification and EV's are adopted through the planning horizon consistent with the most recent MISO Future 3.
- Specific new units are modeled if under construction or with regulatory approval (i.e., IRP cost pre-approval, CON, or signed GIA).
- For electric utilities independently administering their own EWR program, maintain a 2% EWR savings. If the utility is not already at 2%, ramp up the utility's EWR savings to at least 2.0% of prior year sales over the course of 3 years, using EWR cost supply curves provided in the 2021 supplemental potential study for more aggressive potential.[25] EWR savings remain at 2% throughout the study period.

[23] Midcentury datapoints for several climate change variables are available through Great Lakes Integrated Sciences and Assessments (GLISA) and Center for Climatic Research (CCR) at the University of Wisconsin-Madison. This information should be used to aid in establishing forecasts that include the impacts of climate change.

[24] 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.

[25] For EWR cost supply curves, see the Michigan Energy Waste Reduction Potential Study (2021-2040) Report at this link: [MI EWR Statewide Potential Study (2021-2040) Combined (michigan.gov)]

- Achieve and maintain a 50% renewable energy portfolio by 2030 and another 10% from other renewable resources such as voluntary green pricing and distributed generation.
- Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- All storage resources are considered. Energy storage resources are modeled using available best practice methodologies to the extent that such guidelines exist. Allow for multiple market revenue streams where applicable.
- Technology costs for wind, solar, storage and other renewables decline linearly with commercial experience and forecasted at levels resulting in a 30% reduction from Scenario 1 by the end of the 20-year study period.
- Existing renewable energy production and storage tax credits and renewable energy investment tax credits continue pursuant to current law. Federal policy timing may impact modeling.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be informed by the most recently Commission approved state-wide potential study and may be augmented by prior EWR and DR potential studies and/or additional research.
- Existing PURPA contracts are assumed to be renewed. Existing PURPA QFs up to the utility's "must buy" obligation MW threshold are assumed to be renewed unless the QF indicates otherwise either publicly or directly to the utility.
- Existing PURPA QFs greater than the utility's "must buy" obligation MW threshold are assumed to continue operations within the wholesale market beyond the termination date of the contract unless the QF indicates otherwise either publicly or directly to the utility.

Scenario #2 Sensitivities:

1. Fuel cost projections: Increase the natural gas fuel price projections from the base projections to at leastthe high EIA gas price in the most recent EIA ~~Low~~ Oil and Gas Supply forecast. ~~natural gas fuel price projections at the end of the study period.~~ [26]
2. Assume all coal facilities in Michigan are retired by 2030 and Michigan electric sector meets an 80% carbon reduction from the 2005 baseline, modeled as a hard cap on the amount of carbon emissions.[27]
3. Remove the assumed RPS and assume that 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).
4. For electric utilities independently administering its own EWR program, ramp up to 2.5% EWR savings based upon prior year sales within the utility's Michigan jurisdiction.

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[26] ~~For example, the most recent EIA AEO Low Oil and Gas Supply natural gas price is $8.41/MMBtu ($2019) in 2040.~~

[27] Based upon ramping to a net zero carbon power sector by 2035 https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-energy-technologies/

VIII. Michigan IRP Modeling Input Assumptions and Sources

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

	Value	Sources
1 - Analysis Period	• A minimum analysis period of 20 years, with reporting foryears 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 ifapplicable. 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 scenarioand/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 • Retirement assumptions throughout the MISO footprint are consistent with MISO futures development Future 1 and Future 3.
6 - Natural Gas Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity 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 andmade available to all intervening parties.
7 - Coal Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity 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 andmade available to all intervening parties.
8 - Fuel Oil Price nominal dollars $/MMBtu	• Forecasts utilized should align with scenario and/orsensitivity descriptions.	• If utility-specific data is utilized, it should be justified andmade available to all intervening parties.
9 - Energy Waste Reduction Savings MWhs	Base Case: • For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to loadforecast. • For non-incentive earning electric utility, mandated annualincremental savings (1.0%) as a net to load. • Not less than 35% of the state's electric needs should bemet through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3). EWR Base Case Sensitivities: • For savings beyond mandate, incorporate EWR as anoptimized generation resource. Emerging Technologies Scenario: • Ramp up EWR savings at least 2.0% over the course of four years, using EWR Cost Supply Curves provided in the2017 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 • 2021 Energy Waste Reduction Potential Study

10 - Energy Waste Reduction Costs nominal dollars per kWh (Program administrator costs only; participant costs are not to beincluded in this analysis.)	• Current average levelized costs as defined in 2016/2017Potential Studies and Supplemental Modeling reflecting aggressive and cost-effective program savings goals.	• 2021 Energy Waste Reduction Potential Study
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 demandresponse as applicable to the scenario.	• As defined by 2021 Demand Response Potential Study
12 - Demand Response Costs nominal dollars per MW	• Costs/MW by program including all payments, credits, orshared savings awarded to the utility through regulatory incentive mechanism.	• As defined by 2021 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 kWhand 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, mustbe justified and made available to all intervening parties.
15 – Other Resources	• Changes to operation guides • Options which improve reliability (Storage, SVC, HVDC, CVR) • 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 wheresuch 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, other 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 tothose technologies' and options' presently unconventionalnature. 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. • Storage Resource information
16 - Wholesale Electric Prices		• Documentation for wholesale price forecast must beprovided to all intervening parties.
17 – Electric Vehicle Forecasts	Scenario 1 EIA AEO Reference Case Scenario 2 half of vehicle sales are electric by 2030	• EIA AEO Transportation

IX. 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 fromthe 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 as specified in the Michigan Integrated Plan Filing Requirements.
5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled overthe 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 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 goalof 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.

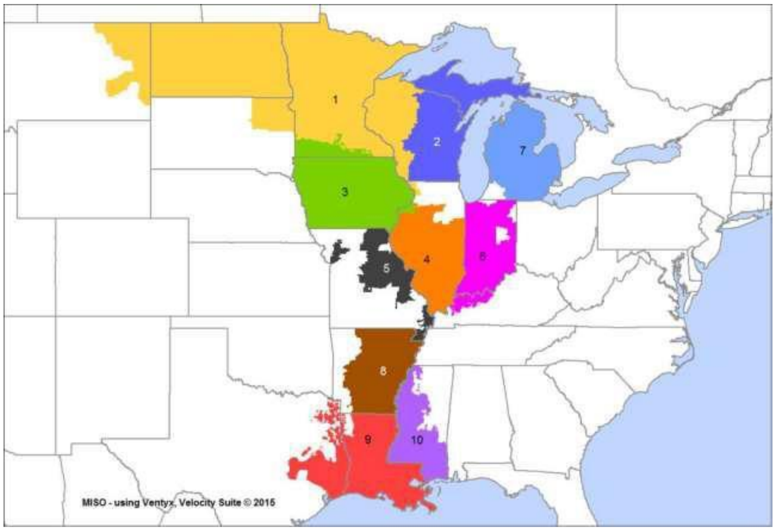
9. For purposes of IRP modeling, forecasted energy efficiency savings should be aggregated into hourly units, coincident with hourly load forecasts, with indicative estimates of efficiencycost and savings on an hourly basis. It is this aggregation and forecast of energy efficiency, to be acquired on an hourly basis that allows EWR to be modeled as a resource in an IRP for planning purposes.
10. Prior to modeling Scenario 1 and Scenario 2, the utilities shall consider and prescreen all 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. To the extent that the utility is proposing early retirement of a generation facility (retirement that results in an undepreciated plant balance and prior to the end of the assumed useful life), the utility should present an NPVRR analysis that compares various financing options.
15. Recognize capacity and performance characteristics of variable resources.
16. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.
17. Take into consideration existing power purchase agreements, green pricing and/or other programs.
18. 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. The utility should explicitly identify revenues that are expected to be earn that are offsets to the net present value of revenue requirements and the assumptions that those revenues are based upon.
19. 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 thefollowing organizations or groups:

Update with Phase II and Phase III participants

Appendix B: Map of MISO Local Resource Zones



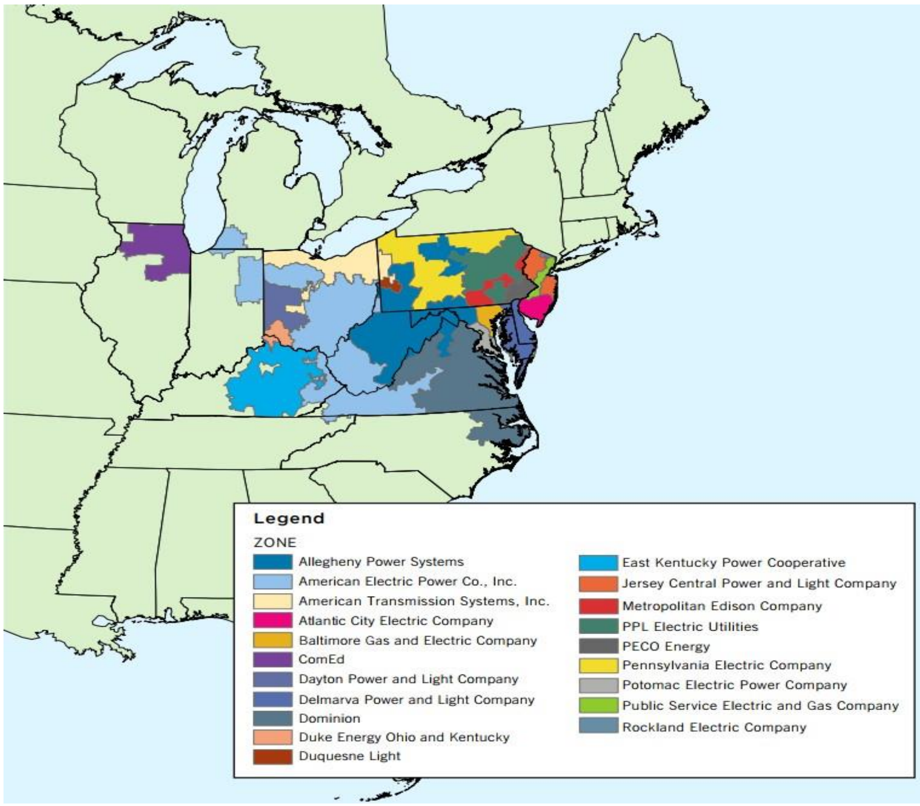
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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

MISO Zone 7 - Rate regulated electric utilities - Alpena Power Company, Consumers EnergyCompany, 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 ispart 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 the following as part of the proceeding:

(a) Conduct an assessment of the potential for energy waste reduction in this state, based on whatis 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 whatis economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already beeninstalled in this state and seek to fully maximize potential benefits to ratepayers in lowering utilitybills.

(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 additionto 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 foradditional 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 includein developing its integrated resource plan, receive written comments and hold hearings to solicitpublic input regarding the proposed modeling scenarios and assumptions.

Appendix E: Environmental Regulatory Timeline

- Updated chart forthcoming.

Integrated Resource Plan

Filing Requirements

Pursuant to Public Act 341 of 2016, Section 6t

Application Instructions for Integrated Resource Plan Filings

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

Schedule

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

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

Filing Announcement

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

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

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

The filing announcement shall include:

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

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

Pre-Filing Request for Proposals

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

a) The utility shall include with the IRP application documentation demonstrating that the RFP process was completed.
b) The utility's RFP process is subject to audit by the Staff.
c) The IRP filing shall include evidence that the pre-filing RFP process was conducted in a manner consistent with the competitive procurement guidance in Case No. U-20852, the Commission's code of conduct, and applicable state, federal, and Commission rules.
d) The RFP shall allow for proposals to provide new supply-side capacity resources to partially meet the requirement, pursuant to MCL

Commented [MKK1]: In workgroup, someone expressed concern that following the competitive procurement guidance is not a "requirement." I think if the word "that" were replaced with "of whether" it would elicit helpful information about the competitive procurement process without implying that following the guidance in U-20852 is a requirement.

460.6t(6).

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

Stakeholder Engagement and Public Outreach Process

Participant engagement early in the development of the IRP is strongly encouraged to: (1) educate potential participants on utility plans; (2) utilize a transparent decision-making process for resource planning; (3) create opportunity to provide feedback to the utility on its resource plan; (4) encourage robust and informed dialogue on resource decisions; and (5) reduce utility regulatory risk by building understanding and support for utility resource decisions. The utility may choose to incorporate some, or all, of the participant input in its analysis and decision-making for the IRP filing.

In the 12 months prior to the IRP filing, each utility is encouraged to host update workshops with interested participants. The purpose of the pre-filing workshop(s) is to ensure that participants have the opportunity to provide input and stay informed regarding: (1) the assumptions, scenarios, and sensitivities; (2) the progress of the utility's IRP process; and (3) plans for the implementation of the proposed IRP. Documentation demonstrating the public outreach process undertaken by the utility shall be included with the IRP filing. Documentation may include:

a) Workshop dates and times, including times outside of the workday.
b) Evidence that a notice of the workshops was provided to the public.
c) Meeting minutes.
d) Meeting or workshop attendance lists.
e) Participant comments on the last approved IRP and/or inputs into the proposed IRP application; and
f) Discussion indicating if or how the public outreach process influenced the IRP.
g) Include descriptions of community outreach efforts for vulnerable communities in the Company's service territory. Vulnerable communities should be identified using the MI EJ Screening Tool or other tools as noted in the Section XVIII.

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

If the stakeholder engagement workshops are not open to the public, two additional in-person public meetings are recommended, as well as at least two additional virtual or hybrid meetings. The public meetings are intended to educate the public on the utility's planning process as well as provide an opportunity for the public to comment. To accomplish this intent, the utility should use best efforts to present the details of the integrated resource planning process in accessible, non-technical language that includes, but is not limited to, descriptions of the impacts of the Company's plans on communities, the environment, and public health.

The public meetings should be offered in the utility's service territory in geographic locations convenient to customers, with advanced notice provided to customers in the utility's service territory. The utility should coordinate with community-based organizations when organizing and promoting meetings about the filing. The utility should solicit input regarding the time, place, and manner of the meetings from the community organizations. The utility is encouraged to consider holding public meetings at a variety of times, including after normal business hours, to encourage attendance. The utility should provide equivalent content and equivalent and sufficient time for robust public response at each session.

When requested 10 business days prior to a meeting, the utility should provide translations of materials for the benefit of those communities whose first language is not English. When requested 10 business days prior to an in-person meeting, the utility should use best efforts to include at least one live interpreter who can translate in the requested language.

If the utility chooses to hold pre-filing workshops, including stakeholder engagement workshops or public meetings, the utility shall prepare a public outreach report to document the outcomes of any pre-filing workshops, and shall file the report with the IRP application. The Company should include in this report a concise general

Commented [MKK2]: The language added to this section follows paragraph 19 of the Consumers IRP Settlement Agreement.

statement of the basis and purpose of the comments received by the Company and how the Company considered, addressed, or rejected the issues raised in those comments.

All presentations, recordings, comments, and transcripts should be maintained on a website in a location open to the public for the duration of the stakeholder outreach process and the duration of the IRP case, until a final commission order is published. When requested within 30 days subsequent to a meeting, the utility will use best efforts to provide a translation of recordings of the meeting in a language specified by the person requesting the translation. The utility should make best efforts to provide the translation recordings within 15 business days after the request is received.

Risk Assessment Methodology

The utility's IRP filing shall include a thorough risk analysis of the proposed resource plan and the optimal plans for each of the scenarios specified in the Michigan Integrated Resource Planning Parameters (MIRPP), as well as all additional scenarios and sensitivities filed with the IRP application. The plans should be feasible and differ in generation mix from the proposed resource plan and MIRPP plans. The intent of the risk assessment is to test the optimized resource strategies and the PCA for each scenario to determine how each strategy would perform in an unexpected range of possible futures. The risk assessment methodology should incorporate the potential impacts of climate change in the forecasts for input variables.[1,2] Utilities are encouraged to link variables that are correlated to or dependent upon one another. The IRP shall include a discussion of the methodology used for risk analysis including the utility's justification for the chosen methodology over other alternatives. Acceptable forms of risk analysis include, but are not limited to, the following: scenario analysis, global sensitivity analysis, stochastic optimization, generating near-optimal solutions, agent-based stochastic optimization, mean-variance portfolio analysis, and Monte Carlo simulation.

Confidential Information

Transparency and the use of data that can be shared with the Commission, the Staff,

[1] https://glisa.umich.edu/summary-climate-information/
[2] https://ccr.nelson.wisc.edu/

and intervenors is encouraged. Proprietary, confidential, and other nonpublic materials used in the development of the forecasts, scenarios, or other aspects of the IRP shall be presented in such a way that the proprietary and confidential nature of the materials is preserved. The use of publicly available data and materials is encouraged in lieu of proprietary and confidential materials and claims that information is proprietary or confidential should be justified by the utility.

Inclusion of specific materials in the IRP filing may be contingent upon appropriate confidentiality agreements and protective orders. Proprietary, confidential, and other nonpublic materials filed as part of the IRP shall be clearly designated by the utility as confidential.

Definitions

The following definitions are provided to aid in ensuring consistency across planning processes.

Distributed Energy Resources - A source of electric power and its associated facilities that is connected to a distribution system. DER includes both generators and energy storage technologies capable of exporting active power to a distribution system.

Non-Wires Alternatives - An electricity grid investment or project that uses distribution solutions such as distributed energy resources (DER), energy waste reduction (EWR), demand response (DR), and grid software and controls, to defer or replace the need for distribution system upgrades.

Vulnerable, Disadvantaged, Underserved Communities – to be defined in coordination with EGLE. See Appendix (IV) below.

Demand-S~~s~~ide Resources - Resources that serve resource adequacy needs by reducing load, which reduces the need for additional generation, including but not limited to EWR, DR, grid and software controls, b~~B~~ehind-~~-~~the-~~-~~meter resources, distribution-~~-~~connected storage, etc.

Co-Benefits – Benefits that are quantified as part of another planning or ~~an~~ evaluation process that are important to the justification of a resource included in the integrated resource plan. Examples include benefits to distribution planning or evaluation of multiple revenue streams. Co-benefits can also include non-energy benefits such as public health or energy affordability.

Commented [MKK3]: Does this mean that DERs would be part of this definition?

Approval of Costs

For the Commission to specify the costs to be approved for the construction of or significant investment in supply or demand-side resources, or contractual agreements, excluding short-term market capacity purchases to meet state reliability mechanism capacity requirements, in accordance with MCL 460.6t(11) through (12), the following information, data, and documents shall be provided:

I) For specific supply-side resources (inclusive of storage technologies) of less than 225 megawatts (MW) (this threshold shall be applied to the nameplate capacity of a project, not individual generators, storage facilities, etc.), that are planned to go into service within three years following the approval of the IRP, the following evidence (covering the lifespan of the project) shall be provided:

   a) A description of the plant size, type, and summary of engineering/design specifications. The description shall also include the following:
      i. Description of fuel use, both primary and back-up, and provisions for transporting and storing fuel;
      ii. Projected annual costs, in accordance with the breakdown specified in the Federal Energy Regulatory Commission Uniform System of Accounts; and
      iii. Annual depreciation on the capital investment.
   b) Projected annual return and income taxes on capital investment.
   c) The operation and maintenance (O&M) costs over the life of the facility described as costs which are variable, in current dollars per kilowatt-hour (kWh), with expenses for fuel and non-fuel items indicated separately; and costs which are fixed, in current dollars per kilowatt.
   d) Projected property taxes.
   e) The rates of escalation of cost, including:
      i. Capital costs.
      ii. O&M costs which are variable and related to fuel.
      iii. O&M costs which are variable and unrelated to fuel.
      iv. O&M costs which are fixed.
   f) The total annual average cost per kWh at projected loads in current dollars for each year of the plan for the proposed facility.
   g) Equivalent availability factors, including both scheduled and forced outage rates.
   h) Capacity factors for each year in the planning period.

Commented [MKK4]: This section should more explicitly require costs related to decommissioning. This is explicitly included in the section on renewable resources, and should also be included here to ensure the correct comparison.

Commented [EK5]: Include sensitivity (both efficiency and outages) to future increases in frequency and magnitude of extreme heat events

i) Operation cycle (i.e., baseload, intermediate, or peaking), identifying expected hours per year of operation, number of starts per year, and cycling conditions for each year in the planning period.
j) Heat rates (efficiency) for various levels of operation.
k) Unit lifetime, both for accounting book purposes and engineering design purposes, with explanations of differences.
l) Lead time, separately identifying the estimated time required for engineering, permitting and licensing, design, construction and pre-commercial operation date testing.
m) Potential socioeconomic impacts, such as employment, for the local region of the proposed supply-side resource, construction of or significant investment in an electric generation facility, or the purchase of an existing electric generation facility.
n) Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.

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

a) Capital, operating and maintenance costs for renewable energy systems (including property taxes and insurance for renewable energy systems).
b) Financing costs.
c) Costs that are not otherwise recoverable in base rates including interconnection and substation costs.
d) Ancillary service costs.
e) Cost of purchased renewable energy credits (RECs) other than those purchased for non-compliance.
f) Cost of Contracts.
g) Expenses incurred as a result of governmental action including changes in tax or other laws.

h) Subtract revenues (i.e., transfer price, environmental attributes, interest on regulatory liability, etc.) through 2029.

i) Recovery to include the authorized rate of return on equity, which will remain fixed at the rate of return and debt to equity ratio that was in effect in base rates when the renewable plan was approved (only through 2029).

j) Provide the following information in relation to renewable resource cost recovery:

   i. Forecast through the end of the renewable plan period of the non-volumetric surcharge; and

   ii. Forecast through the end of the renewable plan period of the regulatory liability balance.

k) Procurement strategy, including power purchase agreements and company owned. Reference the most recent Commission approved Competitive Procurement Guidelines.

l) A description of the decommissioning process, costs, and how the utility intends to provide assurance of proper disposal with consideration of material salvage and recycling for proposed new renewable resources.

Commented [MKK6]: It is reasonable to include here a description of the decommissioning process and cost. But this information should be explicitly required for all resources, not just renewable.

III) Energy Waste Reduction: The utility shall providethe following information in relation to energy waste reduction programs cost approval and recovery. For each individual program or group of programs, provide:

a) Total annual cost including:

   i. Annual O&M cost for each individual portfolio of energy waste reduction programs.

   ii. Annual capital cost for each individual portfolio of energy waste reduction.

   iii. Expected cost-sharing or financial incentive granted to the utility by the Commission.

b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable.

c) Maximum single event demand reduction.

d) Total resource capacity (MW) and type reported to the applicable regional transmission organization (RTO)/independent system operator (ISO).

e) Total energy reduction achieved in megawatt-hours (MWh), broken down by customer class and indicating what portion is energy reduction from low-income households participating in a program.

f) Description of program, including customer enrollment, technology used, and marketing plan.

IV) Demand Response and DER Programs:

The utility shall provide the following information in relation to demand response programs and DER programs cost approval and recovery. For each individual program or group of programs, provide:

a) Total annual cost including:
   i. Annual O&M cost for each individual program of demand response and DER programs.
   ii. Annual capital cost for each individual program of demand response and DER programs.
   iii. Expected cost-sharing or financial incentive granted to the utility by the Commission.
b) Total demand reduction potential (MW), including the amount of load reduction and the expected hours of interruption per day, month, and year for each program, if applicable.
c) Maximum single event demand reduction.
d) Total resource capacity (MW) and type (load modifying resource, emergency demand response, etc.) reported to the applicable regional transmission organization (RTO)/independent system operator (ISO).
e) Total energy reduction achieved (megawatt-hours (MWh)); and
f) Description of program, including customer enrollment broken down by customer class and indicating the portion of customers who are low-income households, technology used, and marketing plan.

Waivers and Process for Smaller and Multistate Utilities

An electric utility with fewer than 1,000,000 customers in this state may request a waiver to any portion of these IRP filing requirements. Any request for a waiver shall include a discussion and justification outlining why the waiver is warranted and in the best interest of its customers. Discussion and justification for the requested waiver shall include a description of the utility's current and forecasted energy and capacity needs, and its plan for meeting those needs over the upcoming ten years.

If the utility requires resolution of a waiver request prior to filing an IRP application, the utility shall file the waiver request no less than 60 days prior to the filing of the IRP application.

An electric utility with fewer than 1,000,000 customers in this state may request approval from the Commission to file an IRP jointly with other smaller utilities. Commission approval is required prior to filing a joint IRP.

A non-multistate Michigan electric utility serving fewer than 1,000,000 customers may elect to file an IRP, based on its specific circumstances, that deviates from these requirements, but that is subject to the Staff's ability to request supplemental information. The filing shall include an explanation of why the deviations are reasonable under its circumstances. The Commission shall review any such filings under the traditional "just and reasonable" standard.

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

IRP Filing, Data, and Documentation

The utility's IRP filing shall demonstrate compliance with MCL 460.6t and include the following items:

a) Letter of transmittal expressing commitment to the approved resource plan and resource acquisition strategy and signed by an officer of the utility having the authority to commit the utility to the resource acquisitionstrategy, acknowledging that the utility reserves the right to make changes to its resource acquisition strategies as appropriate due to changing circumstances.
b) Technical volume(s) that fully describe and document the utility's analysis

and decisions in selecting its proposed resource plan and resource acquisition strategy.

c) The data and information requested in the Commission's IRP filing requirements included herein; and
d) Any other information deemed relevant by the utility.

The utility's IRP filing shall include an IRP document(s) and application information including testimony and exhibits that fully describes and documents the utility's analysis and decisions in selecting its proposed resource plan and resource acquisition strategy. To facilitate a similar format for each utility's application, the utility is encouraged to align its filing with this provided outline and include at least the following items:

I) Executive Summary:

An IRP shall include an exhibit that serves as an executive summary, suitable for distribution to the public. The executive summary shall be an informative non-technical description of the resource plan proposed by the utility and resource acquisition strategy.The executive summary shall summarize the contents of the IRP documentand shall include the following:

a) An overview of the planning period examined in the IRP analysis and application.
b) A brief introduction describing the utility, its existing facilities, new resources being proposed, and implementation strategy.
c) A summary of the state, federal, ISO, RTO resource adequacy regulations applicable to the utility.
d) A summary of the analytical approach used in the utility's analysis and the types of new resources considered.
e) A description of how the analytical approach considered potential resource co-benefits from other planning processes such as distribution or transmission planning.
f) A summary of any retirement analysis performed.
g) A description of how the environmental justice analysis results influenced the utility's proposed course of action.
h) The Company shall include a graph that depicts a stacked bar graph that includes the RTO capacity credit[3] of all existing

[3] For example, MISO Zonal Resource Credit.

resources and PCA resource additions, color designated by resource type, that it will use to serve demand in each year for all planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin.

i) The Company shall include graph that depicts a stacked bar graph that includes the annual energy expected to be produced by all existing resources, PCA resource additions, and market purchases for each year of the planning horizon. The graph shall be color designated by resource type. The graph shall have a line representing expected demand over the length of the planning period.

j) The Company shall include graph that summarizes the total of each of the following pollutants projected using the PCA in the MIRPP Scenario 1 for each year of the planning horizon. A graph should be included for NOx, So2, CO, PM, Pb, Hg, VOC, CO2. The graph should also depict the utility's progress toward or achievement of State, Federal and utility announced goals or requirements by including annotations for those goals on the years they apply.

k) Any other information that would aid the public understanding of the utility's proposed resource plan.

II) Table of Filing Requirements.

The utility shall provide a table that clearly identifies the where in the filing it has met all of the filing requirements. It shall include locations in testimony, exhibits and workpapers.

III) Testimony Introduction:

The utility shall describe resource plans to satisfy at least the objectives and priorities identified in MCL 460.6t. The utility may identify and/or describe additional planning objectives that the resource plan will be designed to meet. The utility shall describe and document its additional planning objectives and its guiding principles to design alternative resource plans that consider the planning objectives and priorities. The introduction shall include the following:

a) General description of the utility's existing energy system, including:

i. Net present value of utility revenue requirements,[2 4] with and without any financial performance incentives for demand-side resources.
ii. Revenue requirement of existing generation and power purchase agreements.
iii. Summary of existing generation and power purchase agreements by fuel type.
iv. Utility's existing capacity resource mix.
v. Utility's service territory and breakdown of customer class composition; and
vi. Description of planning period analyzed.

b) Statement of power need.
c) Identify and explain the basis for the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements, for each year of the analysis used in each scenario and sensitivity evaluated by the utility as part of the IRP process.
d) Market and regulatory environment influencing resource planning decisions:
   i. RTO market and state regulation structure if a multistate utility.
   ii. Potential changes to RTO capacity market.
   iii. Electric customer choice.
   iv. Transmission expansion.
   v. Environmental.
   vi. Renewable portfolio standards; and
   vii. Other.
e) IRP planning process; and
f) Stakeholder report.

IV) Analytical Approach:

a) Describe the modeling process, including the duration of the study;
b) The utility shall describe and identify how its model approach optimizes resources to meet load and demand for all times of the year and for each year of the planning horizons. The utility shall explain how the model considers the seasonal and operational characteristics of all resource types, including monthly generation profiles, forced outages, derates, seasonal or limited

[4] [2]The assumed discount rate shall be included along with a justification for the assumed discount rate. Resultsshould be presented in nominal dollars

availability of resources, etc.

Commented [EK7]: This should also include information regarding consideration of climate change, with specific reference to future increases in frequency and magnitude of extreme heat events, extreme weather events, etc.

c) Describe and provide a justification for the risk analysis approach adopted from the Risk Assessment Methodology section:

   i. The utility shall describe and document its quantification of the risk that affects the evaluation of the various resourceplan options.

   ii. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings affected its decision on a resource plan.

   iii. If multiple forms of risk assessment are presented the utility shall explain why certain risk variables could not be included in or are unsuited for one type of risk assessment or another. Considering a risk variable under multiple forms of risk assessment is not discouraged.

d) The utility shall describe and document the identification of risk variables and/or combinations of risk variables selected, their ranges, probabilities, ranking, and/or weighting that defines the risk quantification which the various resource plan options were judged; describe how these risk variables were judged to be appropriate and explain how these were determined; and describe themodeling tools and data sources employed during the capacity expansion, and other modeling processes.

e) Interactions between risk variables should be captured to the extent that it is practical. Evaluation of variables in isolation is acceptable so long as there exists a comprehensive evaluation of resource plans risks that captures interactions and shows overall risk of appropriate build plans. A comprehensive risk assessment should at least include optimized build plans from the required MIRPP scenarios for the proposed resource plan and any alternative resource plans presented by the utility.

V) Integrated Resource Plan Scenarios and Sensitivities:

a) Include a detailed description of all scenarios and sensitivities.

b) In addition to the utility’s own scenarios and assumptions, the inclusion of the established modeling scenarios and assumptions in the MIRPP approved by the Commission in Case No. U-21219, or as revised by subsequent Commission orders related to IRP modeling parameters and requirements.

VI) Existing Supply-Side (Generation) Resources:

Detailed account of projected energy and capacity purchased or produced by the utility's owned and contracted resources, including cogeneration resources. Include data regarding the utility's current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation for each facility in the portfolio:

a) Overview.
b) Fossil-fueled generating units.
c) Nuclear generating units.
d) Hydroelectric generating units.
e) Non-biomass Renewable generating units.
~~e)~~f) Biomass generating units
g) Energy storage facilities.
~~f)~~h) Distributed Energy Resources.
~~g)~~i) Power purchase agreements: energy and capacity purchased or produced by the utility from a contracted resource, including any cogeneration resource.
~~h)~~j) RTO capacity credits and modeling of existing units (such as capacity factor, heat rate, outage rate, in-service and retirement dates, operating costs, etc.).
~~i)~~k) Spot market purchases and off-system sales.

VII) Demand-Side Resources:

Historical and projected load management and demand response programs for the utility in terms of MW and Midcontinent Independent System Operator, Inc., Zonal Resource Credits (ZRCs) and the projected costs for those programs.

a) Provide data on projected enrolled capacity and demand response events for each program. The following items are to be included:
    i. Description of current demand response and load management programs for the IRP study horizon, including the amount of load reductions and the expected hours of interruption per day, month, and year for each program.
    ii. Review the historic performance of existing demand-side programs in delivering benefits and how the utility used such

information in its demand response resource decisions.

iii. Describe the utility's method for determining whether to purchase energy rather than relying on demand response.

iv. A description of any other programs the utility is considering that could potentially expand demand response resources, including expected load reductions and operating parameters.

VIII) Renewables and Renewable Portfolio Standards Goals:

Projected energy purchased or produced by the utility from renewable energy resources.

a) Describe how the electric provider will meet existing renewable energy standards. If the level of renewable energy purchased or produced is projected to drop over the planning periods, the utility must demonstrate why the reduction is in the best interest of ratepayers.

b) Specify whether the number of MWh of electricity used in the calculation of the renewable energy credit portfolio will be the previous 12-month period of weather-normalized retail sales or based on the average number of MWh of electricity sold by the electric provider annually during the previous three years to retail customers in this state.

c) Include the expected incremental cost of compliance with existing renewable energy standards for the required compliance period.

d) A description of how the electric provider's plan is consistent with the renewable energy goals required by the Michigan Legislature (e.g. 35% combined renewable energy and energy waste reduction goal by 2025);

e) Describe the options for customer-initiated renewable energy that will be offered by the electric provider and forecast sales of customer-initiated renewable energy.

f) Describe how the electric provider will meet the demand for customer-initiated renewable energy.

~~f)~~g) The renewable resources available shall include economic distribution connected solar to be modeled by bundling resources installed at the customer level to compare the total economic costs to the utility of distributed generation as a resource to other selectable supply-side resources, consistent with the methodology used for EWR. The Company will develop a model that accounts for all utility costs and/or incentives associated with participating and non-participating distributed generation customers.

The following non-exhaustive list suggests several elements that may be included:

a) Sales forecast through 2021 for compliance with the renewable energy standard, through 2025 toward meeting the 35% goal, and through the study period.
b) Detailed resource plan:
    i. Describe the utility's planned renewable energy credit portfolio.
    ii. Forecast RECs obtained via Michigan incentive RECs.
    iii. Forecast expected compliance levels by year to meet the renewable portfolio targets.
    iv. Identify key assumptions used in developing these forecasts and the proposed resource portfolio.
    v. Identify risks which may drive performance to vary.

IX) Peak Demand and Energy Forecasts:

A long-term forecast of the utility's sales and peak demand under various reasonable scenarios. Include details regarding the utility's plan to eliminate energy waste, including the total amount of energy waste reduction expected to be achieved annually, and the cost of the plan:

a) A forecast of the utility's peak demand and details regarding the amount of peak demand reduction the utility expects to achieve, and the actions the utility proposes to take in order to achieve that peak demand reduction.
b) Subsections:
    i. Key variables used to develop forecast.
    ii. Long-term forecasting methodology.
    iii. Forecasting uncertainty and risks.
    iv. Historical growth in electric sales for the previous five years, including a record of its previous load forecasts (can be supplied in workpapers).
    v. Base Case deliveries and demand forecast.
    vi. Alternative forecast scenarios and sensitivities in accordance

with the Commission’s final order in Case No. U-21219, or subsequent Commission orders relating to IRP modeling parameters and requirements.

vii. Include detailed information about how the forecasts used for IRP modeling align with forecasts used for distribution planning.

viii. Detail information about distributed energy resource adoption and operation.

ix. Detail electric vehicle adoption assumptions and impacts to overall peak demand and energy forecasts.

x. Detail additional electrification adoption assumptions and impacts to overall peak demand and energy forecasts.

X) Capacity and Reliability Requirements:
The utility shall indicate how it complies, and will comply, with all finalized state federal, ISO, RTO capacity and reliability regulations, laws, rules and requirements, (such as planning reserve margins, system reliability and ancillary service requirements) including the projected costs/revenues of complying with those regulations, laws, and rules. The utility shall identify any finalized changes to the applicable state, federal, ISO, or RTO capacity and reliability regulations, laws, rules and requirements that have occurred since its last IRP fining, including narrative that identifies how its PCA satisfies those requirements. The utility shall include data regarding the utility’s current generation portfolio, including the age, capacity factor, licensing status, and remaining estimated time of operation foreach facility in the portfolio.

XI) Transmission Analysis:
In accordance with MCL 460.6t(5)(h), the utility shall work with their local transmission owner to include an analysis ofpotential new or upgraded electric transmission options for the utility. The utility’s analysis shall include the following information:

a) The utility shall work with their local transmission owner to assess the need to construct new or modify existing transmission facilities to interconnect any new generation and shall reflect the estimated costs of those transmission facilities in the analyses of the resource options.

b) In collaboration with their incumbent transmission owner, include an analysis of any co-benefits of storage, specifically the transmission system benefits associated with transmission interconnected storage that is not designated as a storage as transmission only asset.

c) A detailed description of the utility's efforts to engage local transmission owners throughout the utility's IRP process. To inform the IRP process and assumptions, a meeting schedule should be set in advance. The filing should include the pre-decided meeting schedule, any documentation that supports requested extensions of the initial pre-decided timing, and a summary of meetings that ultimately took place.

d) Detailed meeting minutes for utility/transmission owner meetings should include any requested studies, discussions about assumptions and any conclusions made during the meeting, alternatives that were reviewed, any other pertinent information that can be made public or provided through typical contested case confidentiality agreements.

e) Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns.

f) Any information provided by their local transmission owner indicating theanticipated effects of fleet changes proposed in the IRP on the local resource zone's (LRZ) capacity import limit (CIL) transmission system, including both generation retirements and new generation, subject to confidentiality provisions.

Any information provided by their local transmission owner, including costand timing, indicating potential transmission options that could impactthe utility's IRP by: (1) increasing import or export capability; (2) facilitating power purchase agreements or sales of energy and capacity both within or outside the planning zone or from neighboringRTOs; (3) transmission upgrades resulting in increasing system efficiency and reducing line loss allowing for greater energy delivery and reduced capacity need; and (4) advanced transmission and distribution network technologies affecting supply-side resources ordemand-side resources; (5) estimated interconnection costs for new resources (6) potential siting locations that may provide transmission system benefits.

g) In collaboration with their local transmission owner, any information regarding (1) identification of system locations or regions where energy resources can interconnect to the transmission system with minimal transmission investment, (2) recent studies that indicate ways in which the capacity import or export capabilities can be increased or may change and the resulting impacts to the local clearing requirement.
h) Any transmission studies performed by their local transmission owner that support the resource plan proposed by the utility.
i) In conjunction with the local transmission owner, provide an analysis of transmission costs for access to out of state resources conducted by either the RTO, transmission owner(s), and/or utility.
j) Provide RTO reports or web links to report locations that contain information relied upon to support model assumptions or other IRP decisions.

XII) Fuel

The utility shall include the following:

a) Overview.
b) Natural gas price forecasts under the various scenarios.
c) Oil price forecasts under the various scenarios.
d) Coal price forecasts under the various scenarios.
e) Delivered natural gas prices to existing and new utility-owned generating plants.
f) Delivered oil prices to existing and new utility-owned generating plants.
g) Delivered coal prices to existing and new utility-owned generating plants.
h) Projected annual fuel costs under the various scenarios; and
i) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new and existing generation facility.

XIII) Resource Screen:

Describe the utility's options of resources, including combinations of resources constructed as a single facility (such as storage combined with a generation source), to serve future electric load such as utilizing existing and planned resources, build a new facility, purchasing capacity from the market on a short-term basis, and purchasing capacity through a power purchase agreement. The following sections shall discuss each option in detail and options shall be considered in combination to serve future electric load. As described below, workpapers with information on the costs of eachresource option and combination of resource options shall be provided with the utility's filing:

a) Existing and planned resources.
b) New build:
    i. New generation technology and operating assumptions.
    ii. New generation development costs.
    iii. New energy integration of storage technology and operating assumptions; including all storage options.
    iv. New energy storage development costs.
    v. Development costs and operating assumptions for combinations of resources constructed as a single facility.
c) Distributed Energy Resources inclusive of non-wires alternatives identified in other planning processes.
d) Demand-side Resources inclusive of non-wires alternatives identified in other planning processes.
e) Market capacity purchases:
    i. Regional market supply outlook.
    ii. Availability of market capacity.
    iii. Market capacity price assumptions.
f) Long-term power purchase agreements.
g) Transmission resources:
    i. Overview.
    ii. Existing import and export capability.
    iii. Transmission network upgrade assumptions for the IRP; and
    iv. Import and export impact on resource strategy.

XIV) Modeling Results:

An analysis of the capital costs, energy production, energy production costs, fuel costs, energy served, capacity factor, emissions of the pollutants

identified in Appendix A (levels and costs), andviability of all reasonable options available to meet projected energy and capacity needs, including, but not limited to, existing electric generation facilities in this state. The following suggest specific items to be included.
They are not exhaustive.

a) Description of IRP portfolio design strategy (portfolio optimized for least cost, value maximization, reliability, risk minimization, environmental specification etc., or a particular combination).
b) Results for all MIRPP required scenarios and sensitivities, additional utility scenarios and sensitivities, and the proposed resource plan that include annual revenue requirements, present value of annual revenue requirements and netpresent value of revenue requirements, and portfolio capacity including additions and retirements. Include monthly and annual energy pricing, and resource capacity, emissions of the pollutants identified in Appendix A, and load factors.
c) Base case portfolio options to be selected from.
d) Analysis of IRP results.
e) Risk assessment presented with graphics and data that illustrate stochastic risk analysis results such that the probability distributions are clearly defined along with relative positions of the distributions so that plans can be directly compared on a single graph. The use of a box and whisker plot and/or efficient frontier plot is recommended.

XV) Proposed Resource Plan

Include a detailed description of:

a) The type of generation technology proposed for a generation facility or combination of resources constructed as a single facility contained in the plan and the proposed capacity of the generation facility or combination of resources constructed as a single facility, including projected fuel costs under various reasonable scenarios.
b) Plans for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments, including any transmission or distribution infrastructure that would be required to support the proposed construction or investment, and power purchase agreements.

c) The projected long-term firm gas transportation contracts or natural gas storage the utility will hold to provide an adequate supply of natural gas to any new generation facility; and
d) How the utility will meet local, state, and federal laws, rules, and regulations under the proposed course of action.

The utility shall describe the process used to select the proposed resource plan, including the planning principles used by the utility to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall describe how its proposed resource plan satisfies the following:

a) Strike an appropriate balance between the various planning objectives specified.
b) Utilize renewable and demand-side resources to comply with existing laws, goals and, in the judgment of the utility, are consistent withthe public interest to achieve state energy policies; and
c) In the judgment of the utility, the proposed resource plan, in conjunction with thedeployment of demand response measures, has sufficient resources toserve load forecasted for the implementation period.

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the proposed resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain:

a) A schedule to report the status of an approved plan in accordance with MCL 460.6t(14);
b) A schedule and description of actions to implement ongoing and planned demand-side programs and demand-side rates.
c) A schedule and description of relevant supply-side resource research, engineering, retirement, acquisition, and construction.
d) A net present value revenue requirement comparison of its proposal and reasonable alternatives over the planning period utilized in the analysis. It shall also include the calculation and comparison of the net present value revenue requirement of the utility’s proposed resource plan and any alternative resource plans including the alternative resource plans resulting from theCommission-approved modeling scenarios. In addition,

the utility shall provide support for its chosen discount rate and discuss how the results of its analysis would change with different discount rate assumptions.

e) A detailed analysis of any benefits from resources that provide co-benefits to distribution or transmission planning (such as reliability and resilience benefits) when those benefits are unable to be captured through capacity expansion modeling runs, to the extent that the co-benefits were relied upon for justification of resource decisions.
f) A description of how, to the extent practical, the construction or investment in new resources in this state will be completed using a workforce composed of residents of this state.
g) A description of, to the extent practical, the construction of new resources in this state will be completed using materials sourced from this state.

XVI) Rate Impact and Financial Information:

Projected year-on-year impact of the proposed resource plan (and other feasible options) for the periods covered by the plan, covering the following accounts:

a) Revenue requirement.
b) Rate base.
c) Plant-in-service capital accounts.
d) Non-fuel, fixed operations and maintenance accounts.
e) Non-fuel, variable operations and maintenance accounts.
f) Fuel accounts.
g) Emissions cost.
h) Effluent additive costs; and
i) Projected change in generation plant-in-service.

The utility shall describe the financial assumptions and models used in the plan. The resource plan shall include, at a minimum, the following financial information,together with supporting documentation and justification:

a) The general rate of inflation.
b) The allowance for funds used during construction rates used in the plan.
c) The cost of capital rates used in the plan (debt, equity, and weighted)

Commented [EK8]: Would it be possible to incorporate the stranded asset and climate risk of fossil fuel facilities? For example, California's Department of Insurance requires disclosure of what it considers "high-risk fossil fuel assets." What are the risks and liabilities of existing and new facilities in carbon-constrained future?

and the assumed capital structure.

d) The discount rates used in the calculations to determine present worth.
e) The tax rates used in the plan.
f) Net present value of revenue requirements for the plan.
g) Nominal revenue requirements by year; and
h) Average system rates per kWh by year.

If the utility is proposing retirement of generation facilities that are expected to have an undepreciated book balance at the time of retirement, the utility shall include an analysis of various financing options for the remaining book balance if the utility is asking for specific treatment of the undepreciated book balance in its IRP. The utility shall:

a) include an analysis of various financing options for the remaining book balance.

b) identify the impact the different financing options have on the net present value revenue requirement of the proposed resource plan over the entire planning horizon.

c) provide detail to support how the financing treatment requested is the most reasonable and prudent financing means.

XVII) Environmental Considerations and Environmental Justice:
Describe how the utility's resource plan and any alternative resource plans presented in the application will comply with all applicable local,state, and federal environmental regulations, laws, and rules:

a) Include a list of all environmental regulations that are applicable to the utility fleet. Identify which regulations apply to which resources.
b) Include all capital costs for compliance with new and reasonably expected environmental regulations for existing fleet assets in the utility IRP**.**
~~b)~~
c) Include a chart that compares the total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall

identify and justify its use of a carbon counting methodology identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases.[5] The utility is encouraged to use either of the two net short approaches, but should make best efforts to move toward hourly accounting in order to determine the utility's progress towards 100% clean energy as opposed to net zero carbon emissions.

d) Identify any fossil-fuel assets that are considered high-risk assets from a climate perspective.

~~d)~~e) If the Company is proposing retirement of an existing resource, clearly identify the capital cost for environmental regulations and other capital investments in the facility. Costs that are identified as avoided capital costs shall also be identified as avoided capital costs due to becoming cost of removal, or fully avoidable capital costs.

~~e)~~f) Hold a technical conference with MPSC and EGLE staff within 30 days after the filing to discuss the environmental and emission related data included in the filing testimony, exhibits, and workpapers.

~~f)~~g) Provide and make publicly available emission data to inform the Department of Environment, Great Lakes, and Energy Advisory Opinion consistent with the specifications in Appendix A.

Commented [MKK9]: I think we should clarify that this information doesn't just go to EGLE, it is also publicly available.

~~g)~~h) Identify, quantify and provide evidence in the filing that shows progress in meeting any state, federal or utility announced carbon reduction goals. Illustrate how each optimized build plan for each MIRPP scenario, the proposed resource plan, and the previously approved plan perform in meeting those goals throughout the planning period. [6] [7]

XVIII) Exhibits and Workpapers:

The filing shall include exhibits and workpapers as outlined below, subject to

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[5] Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases[5], https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019

[6] Governor Gretchen Whitmer signed Executive Directive 2020-10 (ED 2020-10) regarding the urgent threat to the environment, economy, and the health and well-being of Michigan's residents posed by climate change and its implications. ED 2020-10 committed Michigan to pursuing a reduction of at least 26 to 28 percent in Greenhouse Gas (GHG) emissions below 2005 levels by 2025 and economy-wide carbon neutrality to be achieved no later than 2050 and maintained thereafter.

[7] April 22, 2021, President Joe Biden announced carbon reduction targets for the United States building upon carbon reductions to date. The new targets call for an economy-wide net GHG reduction of 50 to 52 percent from 2005 levels by 2030 and net zero GHG emissions economy-wide by no later than 2050.

any license or other confidentiality restrictions that are unable to be resolved by issuance of a protective order.

a) The Company shall include an exhibit containing a table that designates where each filing requirement is included within its testimony, exhibits, and workpapers with appropriate page and section numbers.
b) The Company shall include an exhibit that depicts a stacked bar graph that includes the RTO capacity credit of all existing resources and new resources for all scenarios and sensitivities, color designated by resource type, in each of the planning years. The graph shall have a line representing expected demand over the length of the planning period with the inclusion of the necessary planning reserve margin.
c) The Company shall include an exhibit that depicts a series of stacked bar graphs that include the energy expected to be produced by all existing resources, new resources, and market purchases for each planning year and for all MIRPP required scenarios and sensitivities. Each graph shall be color designated by resource type. Each graph shall have a line representing expected demand over the length of the planning period.
d) Include a chart that compares the total projected carbon emissions under each scenario and sensitivity analyzed, including quantifying the carbon emissions projected in each sensitivity as a percentage of the carbon emissions presented in the base scenario associated with that sensitivity. The utility shall identify and justify which of the carbon counting methodologies it used for all scenarios and sensitivities. The methodology should be one identified in Electric Power Research Institute, Methods to account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases.[8]
e) Any workpapers used in developing the application, supporting testimony, and IRP. Such workpapers shall, when possible, be provided in electronic format with formulas intact.
f) Any modeling input and output files used in developing the application,

[8] https://ghginstitute.org/wp-content/uploads/2019/04/EPRI-Wholesale-Power-Report-Published-2019.pdf, March 2019.

supporting testimony, resource plan, and any alternative plans. Such modeling input and output files shall, when possible, be provided in electronic format with formulas intact. The utility shall also identify each modeling program used and provide information for how interested parties can obtain access to such modeling program. Modeling inputs and outputs in the model-dependentbinary format should be made available to parties that obtain a license.

g) Cost data**,** estimates**,** and co-benefit analyses that were used in the resource screening process or in any other way to determine resource selection of each electric resource that was considered either individually or in combination with other resources constructed as a single facility, including distributed energy resources, storage, and renewable energy resources.

h) A description, including estimated costs of each alternative proposal received by the utility.

i) A discussion of any differences between its short-term fuel price forecasts and capacity price curve in the IRP filing, and the short-term fuel price forecasts and capacity price curve in its last power supply cost recovery proceeding.

j) Identification and justification of the forecasted price of energy, capacity, and fuels, and of peak demand and energy requirements used in the IRP. The utility shall identify its base case forecasts and a range of sensitivities for each such factor and explain how those sensitivities were identified. If the base case forecast(s) differs from recent previous forecasts submitted by the utility to the Commission in other cases, the utility shall provide an explanation for such differences.

k) 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 shallanalyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utility's generation fleet.

l) Estimated annual emissions of carbon dioxide and greenhouse gases, particulates, sulfur dioxides, oxides of nitrogen, and mercury per year and over the life of the facilities included in their IRP. Include lifecycle greenhouse gas emissions.

m) The assumed retirement dates of the facilities included in the IRP, with justification provided for the assumed retirement dates.

n) An analysis that contains an individualized cost estimate for electric resources that were considered, including renewable alternatives, such as solar, wind, or solar plus storage, and such cost estimates forall alternative proposals, solicited or unsolicited, received by the utility.

o) Electricity market forecasts utilized.

p) Other documents and data underlying the IRP analysis.

Appendix 1

I. Scope of Portfolio Build Plan Evaluated in Scenarios as follows (herein referred to collectively as portfolios):

a. Portfolio 1: Previously approved portfolio (status quo; PCA in previously approved IRP) run in the MIRPP Scenario 1 (optimized through the current study period).
b. Portfolio 2: Utility proposed course of action (PCA) portfolio run in MIRPP Scenario 1.
c. Portfolio 3: Optimized portfolio in MIRPP Scenario 1.
d. Portfolio 4: Optimized portfolio in Scenario 1 with high load sensitivity.
e. Portfolio 5: Reasonable Alternatives to the PCA presented by the utility in MIRPP Scenario 1.

II. The utility will provide the following ~~facility/unit level~~ data ~~and total annual fleet data,~~ in an Excel spreadsheet(s) expressed in total tons~~,~~ and in tons per MWh and per MWBtu to EGLE for each of the units that are either owned or under purchase agreement by the utility in addition to total annual fleet data:

Commented [KRB10]: Specifying here that this should include *both* the units owned by the utility and the ones that power is purchased from (even if they are not owned by the utility).

a. Emissions of the following:
b. sulfur dioxide (SO_2)
c. nitrogen oxides (NO_x)
d. carbon monoxide (CO)
e. particulate matter (PM)
f. lead (Pb)
g. mercury (Hg)
h. volatile organic ~~carbon~~ compounds (VOC)
i. carbon dioxide (CO_2)

These data will be presented as raw numbers/units and as the aggregate change comparing the three portfolios - #1, #2 and #5. The methodology used to determine the emissions from the respective regional transmission organization purchases will be explained. The utility will propose a sample template of what would be provided in the IRP filing to EGLE for agreement 30 days before the filing.

III. Analyze all portfolios to identify and quantitatively assess the potential impacts to vulnerable communities (as defined collaboratively with EGLE). The utility will perform the analysis using the~~an~~ ~~Environmental Justice Screening and Mapping Tool (EJSCREEN) or the~~ Michigan Environmental Justice Screening Tool (Mi EJSCREEN) or the US EPA's Environmental Justice Screening and Mapping Tool (EJSCREEN), if the Mi EJSCREEN tool is not finalized. The screening will include an assessment of vulnerable communities within a 3-mile radius of each facility for all facilities, including reporting the total population and any indicators and total index results above the 75th percentile. This quantitative assessment

Commented [KRB11]: Re-written to prioritize the usage of the Mi EJScreen tool.

should address air emissions and early retirement of fossil fuel-fired facilities. Explain how these considerations were considered in the utility's decision.

IV. Using the vulnerable communities identified in the analysis above, qualitatively assess the impacts of all portfolios including utility proposed early retirements of fossil fuel-fired facilities. The analysis should address water quality, waste disposal, and expected changes in land use for new or retiring resources to the extent known at the time of filing.

V. To determine health impact estimates for air emissions, the utility will use the environmental Benefits Mapping and Analysis Program – Community Edition (BenMAP-CE), the Co-Benefits Risk Assessment (COBRA) Health Impacts Screening and Mapping Tool, or a similar analytical tool that calculates $PM_{2.5}$-related health impacts for a range of health outcomes. The utility will report the total $PM_{2.5}$-related health impacts as number of instances and monetary value for the entire contiguous US and with a ~~mapping features and~~ spatial resolution down to at least the county level within Michigan. Based on the pollutant parameters compatible with the chosen tool, this air emissions data analysis will be performed to provide health impact estimates to assess:

a. Overall fleetwide health impacts of utility proposed early retirement of fossil fuel-fired facilities and renewable energy adoption. Results, including impacts and associated costs, will be presented for portfolios #1, #2, and #5 for each facility/unit.

b. Impacts on vulnerable communities identified above (within a 3-mile radius). Results, including impacts and associated costs, will be presented for all five listed portfolios for each facility/unit.

VI. If a decrease in PM2.5 emissions is not demonstrated at all electric generating unit(s) within a 6-mile radius of an identified disadvantaged community, including any new proposed units that could reasonably be expected to locate within the 6-mile radius, conduct dispersion modeling for PM2.5 including all electric generating unit(s) within a 6-mile radius of the identified disadvantaged community. The current emissions should be used to establish a baseline modeling demonstration by which to compare the future impacts of portfolio #2. Any dispersion analysis conducted pursuant to this item, doesn't necessarily need to be a refined analysis. A screening analysis employing reasonable assumptions is acceptable. How refined the analysis is at the discretion of the utility. The goal of this analysis is to assess how the ambient concentrations of PM2.5 in vulnerable communities may be affected and to encourage an assessment of ambient impacts in the siting of any new units.

VII. For resources located within the non-attainment areas, or an area that may be designated nonattainment based on reasonably known information at the time of filing, in the electric utility service territory, identify and assess their impact to the non-attainment status for the

Commented [KRB12]: Adding some information about what it means to be a "similar model"

Commented [KRB13]: Updated the text here to clarify that the total impacts should be stated across the entire US and then by county in Michigan

Commented [KRB14]: It would be helpful to have the breakdown by facility, so one can see if there are any disproportionately high polluters, in addition to the total fleetwide impacts.

Commented [KRB15]: This seems to contrast the statement that information must be provided down to at least the county level, in terms of spatial resolution, above.

Commented [EK16]: Just to clarify this is an additional analysis above and beyond the previous US-wide analysis with more detailed local modeling?

portfolio #2 listed above as compared to portfolio #1, and qualitatively support in testimony. The assessment should consider all nonattainment pollutants (i.e., SO2 and ozone), as well as their precursors (i.e., NOx and VOCs).

VIII. Narrative discussion of the quantitative and qualitative health and environmental impacts based on the analysis above, methodologies, data sources, and related observations. Explain how these considerations were considered in the utility's decision, including community feedback on these findings.

IX. Hold a technical conference with MPSC and EGLE staff within 30 days of the filing to discuss the environmental and emission related data included in the filing testimony, exhibits and workpapers.