MICHIGAN INTEGRATED RESOURCE PLANNING PARAMETERS

Pursuant to Public Act 341 of 2016, Section 6t

Draft 2022

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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 be viewed as probable and could be considered as bookends on the range of possible future outcomes. Utilities may also include separate additional scenarios and sensitivities in 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

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[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

[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 ofeach 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.

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[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, two modeling 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]
- Technology costs for thermal units and wind track with mid-range industry expectations.

[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 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.
- 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.

[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.

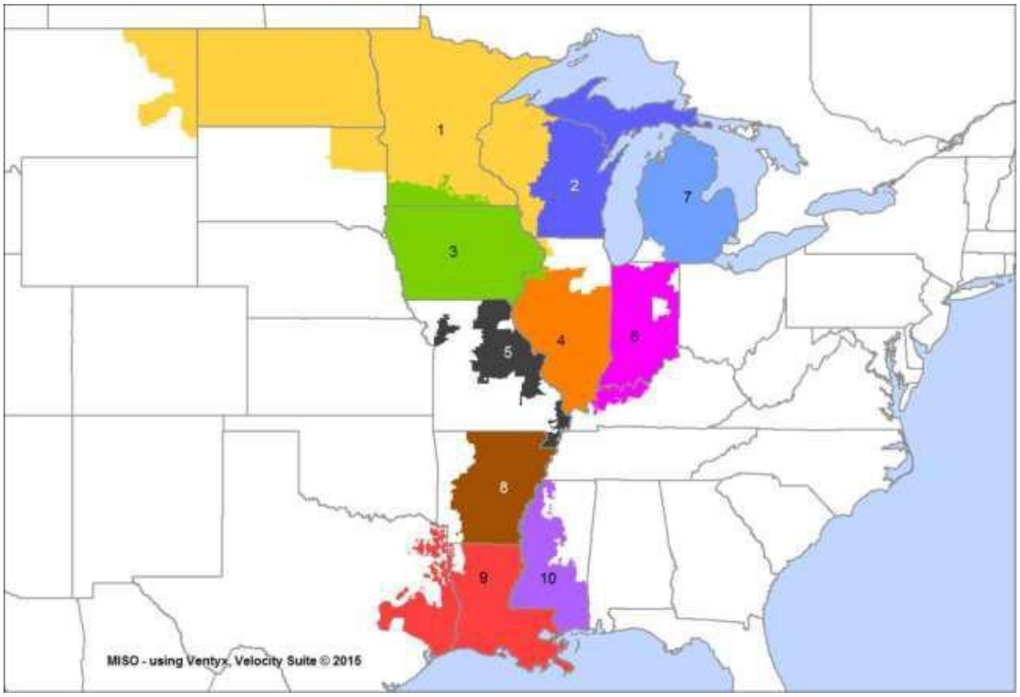
9. For purposes of IRP modeling, forecasted energy efficiency savings should be aggregated into hourly units, coincident with hourly load forecasts, with indicative estimates of efficiencycost and savings on an hourly basis. It is this aggregation and forecast of energy efficiency, to be acquired on 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



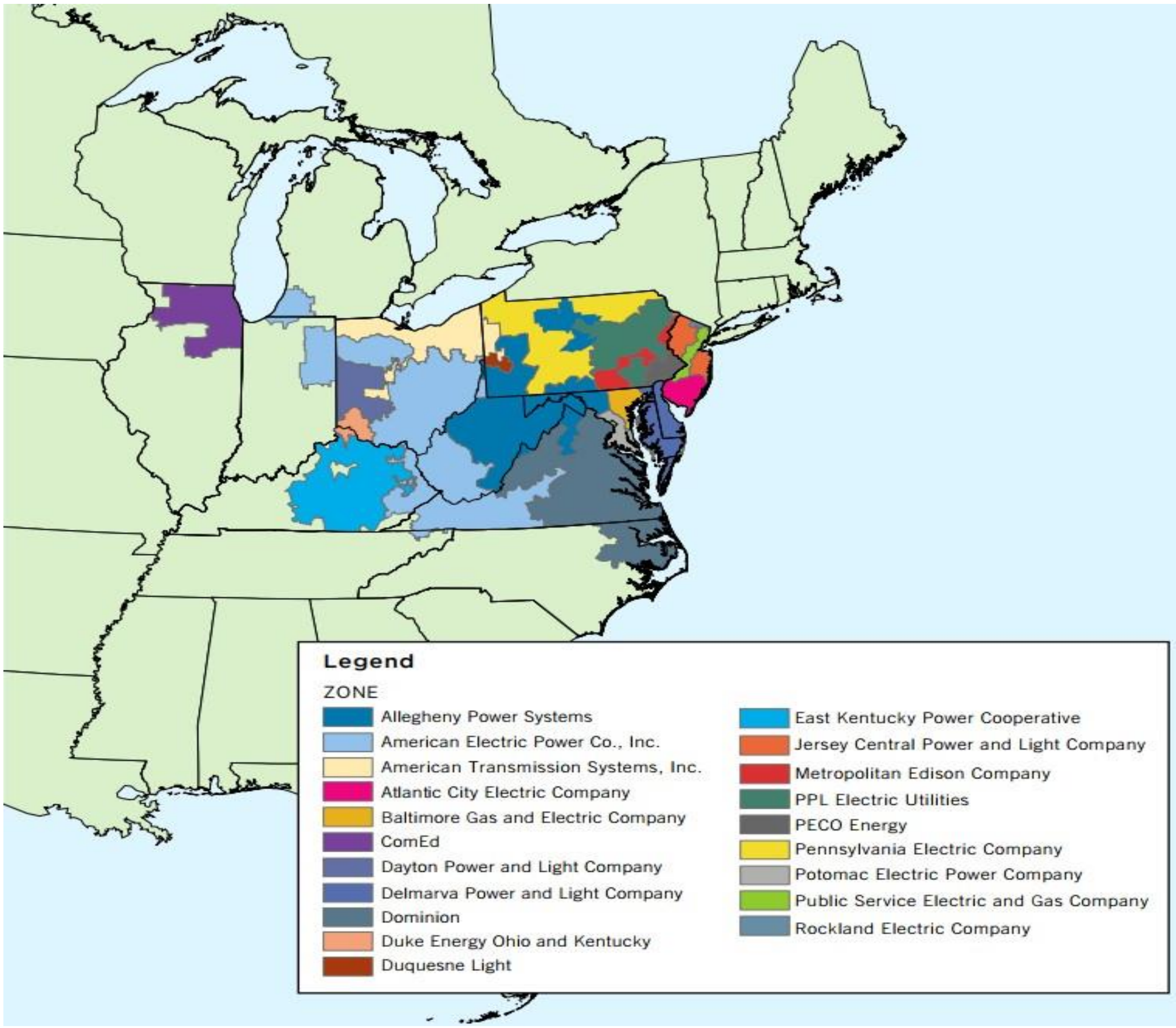
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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.