

# DRAFT INTEGRATED RESOURCE PLANNING PARAMETERS (STRAWMAN PROPOSAL)

Pursuant to Public Act 341 of 2016, Section 6t

August 31, 2017

MAE, MPSC, and MDEQ Staff

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## II. Executive Summary

This draft strawman proposal is submitted by the Michigan Public Service Commission, Michigan Agency for Energy, and Michigan Department of Environmental Quality Staff (Staff) to stakeholders for comment as part of the implementation of the provisions of Public Act 341 of 2016 (PA 341) Section 6t. This draft includes three proposed integrated resource plan (IRP) modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Upper Peninsula, and three proposed IRP modeling scenarios with multiple sensitivities per scenario for the rate-regulated utilities in Michigan's Lower Peninsula. None of the scenarios, sensitivities or other modeling parameters included within this document should be construed as policy goals or even as likely predictions of the future. Instead, the scenarios, sensitivities and modeling parameters are more aptly characterized as stressors utilized to test how different future resource plans perform relative to each other with respect to affordability, reliability, adaptability, and environmental stewardship. 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 strawman proposal also contains numerous modeling assumptions and requirements, requires sensitivities for each scenario, identifies significant environmental regulations and laws that effect electric utilities in the state, and identifies required planning reserve margins and local clearing requirements in areas of the state.

The Demand Response Potential Study is still in development, however the status of the work completed to date is included in this strawman proposal. The assessment of Energy Waste Reduction Potential was very recently completed. Both studies have influence on integrated resource planning and will be incorporated into the Commission's Docket ([Case No. U-18418](#)) for the implementation of the provisions of PA 341 Section 6t.

## III. Background

On December 21, 2016, Governor Rick Snyder signed PA 341 into law, which amended Public Act 3 of 1939 and became effective on April 20, 2017. The law requires the Michigan Public Service Commission (MPSC or Commission), with input from the Michigan Agency for Energy (MAE), Michigan Department of Environmental Quality (MDEQ), and other interested parties to set modeling parameters and assumptions for utilities to use in filing integrated resource plans. PA 341 then requires rate-regulated electric utilities to submit IRPs to the MPSC for review and approval.

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

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

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

#### IV. Energy Waste Reduction Potential Study

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

**Lower Peninsula.** The statewide assessment of energy waste reduction (EWR) potential was built upon existing studies provided by two utility-specific 20-year potential studies conducted in 2016, by GDS Associates, Inc. (GDS). These utility-specific EWR potential studies are considered by Staff to represent potential values which reflect a 'business as usual' assessment of achievable, technical and economic potential consistent with requirements of the prior energy law, Public Act 295 of 2008.<sup>1</sup> To develop additional data points which reflect the incremental EWR potential possible under more aggressive program goals consistent with Public Act 342 of 2016, stakeholders first combined the separate utility-specific potential studies into a Lower Peninsula study, resulting in an assessment of EWR potential under Public Act 295 era, business as usual assumptions. From there, stakeholders developed additional modeling scenarios/sensitivities designed to assess additional cost effective EWR savings available with more aggressive programs.

The business as usual assessment and supplemental study results<sup>2</sup> were combined into one report and can be found on the energy legislation implementation webpage for the EWR Potential Study. This study includes the combined business as usual potential results on pages 1 through 85, with the additional potential identified under more aggressive EWR programs,

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<sup>1</sup> Public Act 295 Energy Optimization programs contained caps on program spending which were removed in the Public Act 342 Energy Waste Reduction programs.

<sup>2</sup> See supplemental potential study for the Lower Peninsula,

[http://www.michigan.gov/documents/mpsc/MI\\_Lower\\_Peninsula\\_EE\\_Potential\\_Study\\_Final\\_Report\\_08.11.17\\_598053\\_7.pdf](http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf).

summarized starting on page 87. The modeling scenarios, assumptions, and sensitivities for the supplemental study are briefly summarized below with details provided on the webpage.<sup>3</sup>

1. Scenario #1: Sensitivity on Incentive Levels – GDS revised the basic analysis of “Achievable Potential” for the Consumers Energy Company and the DTE Energy Company service areas using the assumption that the programs would pay 100% of incremental costs<sup>4</sup> for all measures/bundles of measures that would still pass the Utility Cost Test at the higher incentive level (i.e., if the program’s paid incentives equal to 100% of incremental cost of the measure, as opposed to using the 50% of incremental cost assumption.)

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

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

**Upper Peninsula.** The Upper Peninsula potential study assessment also built upon the foundation of existing utility-specific potential studies. Efforts were made to incorporate assumptions which reflected the additional opportunities for EWR potential of the Upper Peninsula due to the generally higher cost of electricity in that region.

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

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

**Statewide Assessment of EWR Potential.** The additional assessments for EWR potential for the Lower and Upper Peninsulas for the 2017 through 2036 timeframe were completed in mid-August and together form the basis for the Staff’s statewide assessment of EWR potential. These assessments include supply curves for the Lower Peninsula which are incorporated into the Staff strawman recommendations. As previously mentioned, these studies are available on the MPSC Energy Legislation webpage.<sup>5</sup>

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<sup>3</sup> For more details on the assumptions for the supplemental EWR study for the Lower Peninsula, see [http://www.michigan.gov/documents/mpsc/Scenario\\_assumptions-\\_07.09.17\\_599440\\_7.docx](http://www.michigan.gov/documents/mpsc/Scenario_assumptions-_07.09.17_599440_7.docx).

<sup>4</sup> For Low-Income measures, the utilities are assumed to pay 100% of the measure cost.

<sup>5</sup> See supplemental potential study for the Lower Peninsula,

[http://www.michigan.gov/documents/mpsc/MI\\_Lower\\_Peninsula\\_EE\\_Potential\\_Study\\_Final\\_Report\\_08.11.17\\_598053\\_7.pdf](http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf);

See also assumptions for supplemental potential study for the Upper Peninsula,

[http://www.michigan.gov/documents/mpsc/UP\\_EE\\_Potential\\_Study\\_Final\\_Report--memorandum\\_08.09.17\\_598056\\_7.docx](http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx).

## V. Demand Response Potential Study

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

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

**Technical Study.** The technical study will assess the technical, economic, and achievable potential for reducing on-peak electricity usage through demand response programs for all customer classes. The study will estimate demand response potential for the 20-year period beginning in 2016.

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

Demand response programs considered by the study will include, but not be limited to behavioral programs, direct load control programs, and volt/VAR demand-side resource programs at the distribution system level. Pre-existing demand response programs will not be favored over not-yet-existing programs in the calculation of statewide potential.

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

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

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

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

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

## VI. State and Federal Environmental Regulations, Laws and Rules

*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 US Environmental Protection Agency (EPA) to set NAAQS for six criteria pollutants that have the potential of harming human health or the environment. The NAAQS are rigorously vetted by the scientific community, industry, public interest groups, and the public. The NAAQS establish maximum allowable concentrations for each criteria pollutant in outdoor air. Primary standards are set at a level that is protective of health with an adequate margin of safety. Secondary standards are protective of public welfare, including protection from damage to crops, forests, buildings, or the impairment of visibility. The adequacy of each standard is to be reviewed every five years. The six pollutants are carbon monoxide, lead, ozone, nitrogen dioxide, particulate matter, and sulfur dioxide.<sup>6</sup>

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

**Sulfur Dioxide Nonattainment Areas** – In 2010, the EPA strengthened the primary NAAQS for SO<sub>2</sub>, establishing a new 1-hour standard of 75 parts per billion (ppb).

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<sup>6</sup> The most recent NAAQS can be accessed here: <https://www.epa.gov/criteria-air-pollutants/naaqs-table>.

A federal consent order set deadlines for the EPA to designate nonattainment areas in several rounds. Round one designations were made in October 2013, based on violations of the NAAQS at ambient monitors. A portion of Wayne County was designated nonattainment. The area must attain the NAAQS by October 2018. The state's attainment plan was due to the EPA by April 2015.

Round two designations were based on modeling of emissions from sources emitting over 2000 tons of SO<sub>2</sub> per year. A portion of St. Clair County was designated nonattainment in September 2016. Attainment must be achieved by September 2021, and the state's attainment plan is due to the EPA by March 2018.

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

**Cross-State Air Pollution Rule** – The Cross-State Air Pollution Rule (CSAPR) was promulgated to address air pollution from upwind states that is transported across state lines and impacts the ability of downwind states to attain air quality standards. The rule was developed in response to the Good Neighbor obligations under the Clean Air Act for the ozone standards and fine particulate matter standards. CSAPR is a cap and trade rule which governs the emission of SO<sub>2</sub> and NO<sub>x</sub> from fossil-fueled electric generating units through an allowance-based program. Under this program, NO<sub>x</sub> is regulated on both an annual basis and during the ozone season (May through September). Each allowance (annual or ozone) permits the emission of one ton of NO<sub>x</sub>, with the emissions cap and number of allocated allowances decreasing over time. Recently, the EPA promulgated the CSAPR Update, which addresses interstate transport for the 2008 ozone standard and went into effect in May of 2017. In the future, the state will have Good Neighbor obligations for the 2015 ozone standard.

**Mercury and Air Toxics Standards** – Section 302 of the Clean Air Act requires the EPA to adopt maximum available control technology standards for hazardous air pollutants. The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule requires new and existing oil and coal-fueled facilities 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 Air Quality Division of the MDEQ. In June 2015, the US Supreme Court found that the EPA did not properly consider costs in making its determination to regulate hazardous pollutants from power plants. In December 2015, the DC Circuit Court of Appeals ruled that MATS may be enforced as the EPA modifies the rule to comply with the Supreme Court decision. The deadline for MATS compliance for all electric generating units was April 16, 2016.

**Clean Air Act Section 111(b), Standards of Performance for Greenhouse Gas Emissions from New, Modified and Reconstructed Stationary Sources: Electric Utility Generating Units** – New Source Performance Standards (NSPS) are established under Section 111(b) of the Clean Air Act for certain industrial sources of emissions determined to endanger



public health and welfare. In October 2015, the EPA finalized a NSPS that established standards for emissions of carbon dioxide for newly constructed, modified, and reconstructed fossil-fuel fired electric generating units. There are different standards of performance for fossil fuel-fired steam generating units and fossil fuel-fired combustion turbines.<sup>7</sup>

**Clean Air Act Section 111(d), Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units (Clean Power Plan)** – Section 111(d) of the Clean Air Act requires the EPA to establish standards for certain existing industrial sources. The final Clean Power Plan, promulgated on October 23, 2015, addressed carbon emissions from electric generating units. The Clean Power Plan established interim and final statewide goals and tasked states with developing and implementing plans for meeting the goals. Michigan’s final goal was to reduce carbon dioxide emissions by 31 percent from a 2005 baseline by 2030.<sup>8</sup>

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

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

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

**Regional Haze** – Section 169 of the federal Clean Air Act sets forth the provisions to improve visibility, or visual air quality, in 156 national parks and wilderness areas across the country by establishing a national goal to remedy impairment of visibility in Class 1 federal areas from

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<sup>7</sup> 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>.

<sup>8</sup> 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>.

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

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

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

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

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

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

Following a previously promulgated version of the rules and judicial remand, the regulations for existing facilities were promulgated in August 2014. These rules were also challenged and undergoing judicial review. According to the published rules, any facility subject to the existing facilities rule must identify which one of the seven alternatives identified in the best technology available (BTA) standard will be met for compliance with minimizing impingement mortality. The rules do not specify national BTA standards for minimizing entrainment mortality, but instead require that the MDEQ establish the BTA entrainment requirements for a facility on a site-specific basis. These BTA requirements are established after consideration of the specific factors

spelled out in the rule. Facilities with actual flows in excess of 125 million gallons per day must provide an entrainment study with its National Pollutant Discharge Elimination System (NPDES) permit application. While the rules do not specify a deadline for compliance of the rules, facilities will need to achieve the impingement and entrainment mortality standards as soon as practicable according to the schedule of requirements set by the MDEQ following NPDES permit reissuance.

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

State Rules and Laws:

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

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

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

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

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

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

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

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

In developing its IRP, a utility should present an environmental compliance strategy which demonstrates how the utility will comply with all applicable federal and state environmental regulations, laws and rules. Included with this information, the utility should analyze the cost of compliance on its existing generation fleet going forward, including existing projects being undertaken on the utilities generation fleet, and include the relevant future compliance costs within the IRP model.

## **VII. Planning Reserve Margins and Local Clearing Requirements**

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

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

MISO publishes planning reserve margins in its annual Loss of Load Expectation (LOLE) Study Report each November.<sup>9</sup> The MISO LOLE Study Report includes the planning reserve margin for the next ten years in a table labeled, “MISO System Planning Reserve Margins 2017 through 2026,” for the entire footprint. MISO also calculates the local reliability requirement of

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<sup>9</sup> MISO 2017 – 2018 Loss of Load Expectation Study Report published in November 2016, <https://www.misoenergy.org/Library/Repository/Study/LOLE/2017%20LOLE%20Study%20Report.pdf>.

each Zone for the upcoming three years in the LOLE Study Report. 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.”<sup>10</sup> The Local Clearing Requirement for each zone is reported annually with the MISO planning resource auction results in April.<sup>11</sup>

For the southwest corner of the Lower Peninsula, in PJM’s territory,<sup>12</sup> similar reliability requirements are outlined in PJM Manual 18 for the PJM Capacity Market.<sup>13</sup> PJM outlines requirements for an Installed Reserve Margin, similar to MISO’s planning reserve margin on an installed capacity basis, and a Forecast Pool Requirement on an unforced capacity basis, similar to MISO’s planning reserve margin on an unforced capacity basis. PJM also specifies 27 Local Deliverability Areas somewhat similar to MISO’s local resource zones. PJM publishes a Reserve Requirement Study<sup>14</sup> annually in October containing the requirements for generator owners and load serving entities within its footprint for the next ten years.

Discussions are ongoing regarding capacity obligations pursuant to PA 341 Section 6w and it is anticipated that the Commission will provide guidance on the reliability requirements. Until guidance from the Commission is provided, the applicable MISO or PJM reliability requirements should be utilized in the development of utility IRPs.

## **VIII. Modeling Scenarios, Sensitivities, and Assumptions**

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

For utilities located in the Michigan portion of MISO Zone 2 and MISO Zone 7, three modeling scenarios are proposed to be required. There are a total of four unique scenarios included in this draft; the applicability of each is described within the narrative of each particular scenario. Staff notes that Northern States Power-Wisconsin and Indiana Michigan Power Company are utilities located in Michigan that already file multistate IRPs in other jurisdictions. Due to the provisions in PA 341 Section 6t (4) regarding multistate IRPs, Staff has intentionally excluded both Northern States Power-Wisconsin and Indiana Michigan Power Company in the applicability of any of the outlined scenarios.

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<sup>10</sup> Federal Energy Regulatory Commission Electric Tariff, Module E-1, 1.365a. 1.0.0.

<sup>11</sup> MISO Planning Resource Auction results, April 2017, <https://www.misoenergy.org/Library/Repository/Report/Resource%20Adequacy/AuctionResults/2017-2018%20PRA%20Summary.pdf>.

<sup>12</sup> See Appendix C for a map of PJM Local Deliverability Areas.

<sup>13</sup> PJM Manual 18 for the PJM Capacity Market, <https://www.pjm.com/~media/documents/manuals/m18.ashx>.

<sup>14</sup> PJM Reserve Requirement Study, October 2016, <http://www.pjm.com/~media/committees-groups/subcommittees/raas/20160927/20160927-2016-pjm-reserve-requirement-study.ashx>.

## Scenario 1. Business as Usual

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

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

- Natural gas prices utilized are consistent with business as usual projections as projected in the US Energy Information Administration's (EIA) most recent Annual Energy Outlook reference case.<sup>15</sup>
- Footprint-wide<sup>16</sup> demand and energy growth rates remain at low levels with no notable drivers of higher growth; however, as a result of low natural gas prices, industrial production and industrial demand increases.
- Low natural gas prices and low economic growth reduce the economic viability of other generation technologies.
- Resource assumptions:
  - Resources outside MI – Maximum age assumption by resource type as specified by applicable regional transmission organization (RTO).
  - Resources within MI – Thermal and nuclear generation retirements in the modeling footprint are driven by a maximum age assumption, public announcements, or economics.
- Specific new units are modeled if under construction or with regulatory approval (i.e., Certificate of Necessity (CON) or signed generator interconnection agreement (GIA)).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Not less than 35% of the state's electric needs should be met through a combination of EWR and renewable energy by 2025, as per MCL 460.1001 (3).
- For all in-state electric utilities that are eligible to receive the financial incentive mechanism for exceeding mandated energy saving targets of 1% per year, EWR should be based upon the maximum allowed under the incentive of 1.5% and should be based upon an average cost of MWh saved. The model should include a EWR supply cost curve to project future program expenditures beyond baseline assumptions without any cap.<sup>17</sup>
- For all other electric utilities, EWR should not exceed the mandated targets for electric energy savings of 1% per year and should be based upon an average cost of MWh saved.
- Existing renewable energy production tax credits and renewable energy investment tax credits continue pursuant to current law.
- Technology costs for thermal units and wind track with mid-range industry expectations.

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<sup>15</sup> 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.

<sup>16</sup> Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State of Michigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.

<sup>17</sup> For EWR cost supply curves, see the appendices in the supplemental potential study for the Lower Peninsula at this link: [http://www.michigan.gov/documents/mpsc/MI\\_Lower\\_Peninsula\\_EE\\_Potential\\_Study\\_Final\\_Report\\_08.11.17\\_598053\\_7.pdf](http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf).

- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by their respective potential studies.
- Technology costs for solar and other emerging technologies decline with commercial experience.

### **Business as Usual Sensitivities:**

1. Fuel cost projections
  - (a) Increase the natural gas fuel price projections by 300% above the business as usual natural gas fuel price projections.
  - (b) Reduce natural gas fuel price projections to half of the business as usual natural gas fuel projections.
2. Load projections
  - (a) Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates.
  - (b) Reduce the energy and demand growth rates to be half of the business as usual energy and demand growth rates.
3. Increase the EWR resources to at least the EWR potential study maximum achievable potential levels.<sup>18</sup>
4. Disinterest in Demand Response: Residential demand response pricing programs are discontinued. Existing interruptible load programs for all customers (i.e., interruptible tariffs, air conditioning switch programs) are reduced to zero over three years.
5. Increase the combined use of renewable energy and EWR to 50% by 2030.
6. Sensitivity allowing only natural gas fired simple cycle combustion turbines to be selected by the model.

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<sup>18</sup> For maximum achievable potential levels, see the supplemental potential study for the Lower Peninsula, [http://www.michigan.gov/documents/mpsc/MI\\_Lower\\_Peninsula\\_EE\\_Potential\\_Study\\_Final\\_Report\\_08.11.17\\_598053\\_7.pdf](http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf); See also supplemental potential study for the Upper Peninsula, [http://www.michigan.gov/documents/mpsc/UP\\_EE\\_Potential\\_Study\\_Final\\_Report--memorandum\\_08.09.17\\_598056\\_7.docx](http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx).

## Scenario 2. Emerging Technologies

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

Technological advancement and economies of scale result in a 35% reduction in costs for demand response, EWR programs, and other emerging technologies. No carbon reductions are modeled, but some reductions occur due to age- or economics-related coal unit retirements, and higher levels of renewables, demand response, and energy waste reduction. Load forecasts and fuel price forecasts remain at levels similar to the Business as Usual Scenario.

- A robust economy drives technological advancement and economies of scale resulting in a greater potential for demand response, energy efficiency, and distributed generation as well as lower capital cost for renewables.
- Thermal generation retirements in the market are driven by unit age-limits and announced retirements (consistent with business as usual). Company-owned resource retirements are defined by the utility. Retirements of all coal units except the most efficient in the utility's fleet should be considered. Retirement of older fuel oil-fired generation should also be considered in this scenario. Assumptions for unit retirements are not made unless affirmative, public statements to that effect are made by the owner of the generation asset.
- Specific new generating units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation interconnection queue.
- Prior to or during the modeling process, the utilities shall take into account resources that include, but are not limited to: small qualifying facilities (20 MW and under), renewable energy independent power producers (IPPs), large combined heat and power (CHP) plants, and self-generation facilities such as behind-the-meter-generation (btmg) as more fully described in the section IX, "Michigan IRP Modeling Input Assumptions and Sources."
- Existing renewable energy production tax credits and renewable energy investment tax credits continue pursuant to current law.
- Technology costs for thermal units remain stable and escalate at low to moderate escalation rates.
- Technology costs for EWR and demand response programs will be determined by their respective potential studies.
- Technology costs for energy storage resources decline over time, particularly battery technologies and others which can enable supply- and demand-side resources.

### Emerging Technologies Sensitivities:

1. Fuel cost projections
  - (a) Increase the natural gas fuel price projections by 300% above the business as usual natural gas fuel price projections.
  - (b) Reduce natural gas fuel price projections to half of the business as usual natural gas fuel projections.



2. Load projections
  - (a) Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates.
  - (b) Reduce the energy and demand growth rates to be half of the business as usual energy and demand growth rates.
3. Ramp up EWR savings to at least 2.5% of prior year sales over the course of four years, using EWR cost supply curves provided in the 2017 supplemental potential study for more aggressive potential.<sup>19</sup> EWR savings remain high throughout the study period.
4. Renewable energy costs
  - (a) Increase by 35% above anticipated maturity cost curves.
  - (b) Decrease by 35% below anticipated maturity cost curves.
5. Transportation energy: Percentage of electric vehicles in Michigan increases to 10% by 2025. (One out of every ten vehicles on the road in Michigan is electric.)
6. Large electric users: Reduced load due to customers adding CHP, batteries, and/or behind the meter generation (btmg) to offset the high electric rates.

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<sup>19</sup> For maximum achievable potential levels and respective EWR supply curves, see the supplemental potential study for the Lower Peninsula,

[http://www.michigan.gov/documents/mpsc/MI\\_Lower\\_Peninsula\\_EE\\_Potential\\_Study\\_Final\\_Report\\_08.11.17\\_598053\\_7.pdf](http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf);

See also supplemental potential study for the Upper Peninsula,

[http://www.michigan.gov/documents/mpsc/UP\\_EE\\_Potential\\_Study\\_Final\\_Report--memorandum\\_08.09.17\\_598056\\_7.docx](http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx).

### Scenario 3. Environmental Policy

(Applicability: Utilities located in MISO Zone 7)

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

- Demand and energy growth rates are modeled at a level equivalent to a 50/50 forecast.
- Natural gas prices utilized are consistent with business as usual projections as projected in the EIA's most recent Annual Energy Outlook reference case.<sup>20</sup>
- Current demand response, energy efficiency, and utility distributed generation programs remain in place and additional growth in those programs would happen if they are economically selected by the model to help comply with the specified carbon reductions in this scenario.
- Non-nuclear, non-coal generators will be retired in the year the age limit is reached and driven by announced retirements. Coal units will be retired reflecting economics. Nuclear units are assumed to have license renewals granted and remain online.
- Specific new units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario descriptions and considering anticipated new resources currently in the MISO generation interconnection queue.
- Tax credits for renewables continue until 2022 to model existing policy.
- Technology costs for wind, solar and other renewables decline with commercial experience and forecasted at levels 35% lower than in the business as usual case.
- Non-carbon dioxide emitting resources will be increased, due to the constraint on allowable carbon emissions in the model.
- Technology costs and limits to the total resource amount available for EWR and demand response programs will be determined by their respective potential studies.

#### Environmental Policy Sensitivities:

1. Fuel cost projections
  - (a) Increase the natural gas fuel price projections by 300% above the business as usual natural gas fuel price projections.
  - (b) Reduce natural gas fuel price projections to half of the business as usual natural gas fuel projections.
2. Load projections
  - (a) Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates.

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<sup>20</sup> 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.

- (b) Reduce the energy and demand growth rates to be half of the business as usual energy and demand growth rates.
3. 50% carbon reduction by 2030 as a sensitivity.
  4. Assume all coal-fired generation is retired by 2035.
  5. Increase the EWR resources to at least the EWR potential study maximum achievable potential levels.<sup>21</sup>
  6. Transportation energy: Percentage of electric vehicles sales in Michigan increases to 10% by 2025. (One out of every ten vehicles on the road in Michigan is electric.)
  7. Large electric users: Reduced load due to customers adding CHP, batteries, and/or behind the meter generation (btmg) to offset the high electric rates.

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<sup>21</sup> For maximum achievable potential levels, see the supplemental potential study for the Lower Peninsula, [http://www.michigan.gov/documents/mpsc/MI\\_Lower\\_Peninsula\\_EE\\_Potential\\_Study\\_Final\\_Report\\_08.11.17\\_598053\\_7.pdf](http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf); See also supplemental potential study for the Upper Peninsula, [http://www.michigan.gov/documents/mpsc/UP\\_EE\\_Potential\\_Study\\_Final\\_Report--memorandum\\_08.09.17\\_598056\\_7.docx](http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx).

## Scenario 4. High Market Price Variant

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

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

- Natural gas prices utilized are higher than business as usual projections and are consistent with projections in the EIA's most recent Annual Energy Outlook low oil and gas resource technology case<sup>22</sup> where natural gas prices near historical highs drive down domestic consumption and exports.
- Footprint-wide<sup>23</sup> demand and energy growth rates are moderate/robust with notable drivers of higher growth.
- High natural gas prices and moderate/robust economic growth increase the economic viability of alternative technologies.
- Thermal generation retirements in the market are driven by unit age-limits and announced retirements are driven by age and environmental regulations. Company-owned resource retirements are defined by the utility.
- Specific new generating units are modeled if under construction or with regulatory approval (i.e., CON or signed GIA).
- Generic new resources (market and company-owned) are assumed consistent with scenario optimizations considering the current resources in the MISO generation interconnection queue.
- Tax credits for renewables continue until 2022 to model existing policy.
- Technology costs for thermal units remain stable and escalate at low to moderate escalation rates.
- Technology costs for renewables remain stable and escalate at low to moderate escalation rates.
- Technology costs for energy efficiency and demand response remain stable and escalate at low to moderate escalation rates.

### High Market Price Variant Sensitivities:

1. Fuel cost projections
  - (a) Increase the natural gas fuel price projections by 150% above the natural gas price forecast utilized for this scenario.
  - (b) Reduce natural gas fuel price projections to half of the business as usual natural gas fuel projections.

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<sup>22</sup> 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.

<sup>23</sup> Footprint refers to the Model Region specified in the Michigan IRP Modeling Input Assumptions and Sources, or the State of Michigan plus the applicable RTO region. Larger footprints or Model Regions, if used by the utility, are acceptable.

2. Load projections
  - (a) Increase the energy and demand growth rates by at least a factor of two above the business as usual energy and demand growth rates.
  - (b) Reduce the energy and demand growth rates to be half of the business as usual energy and demand growth rates.
3. Grid defection: Reduced load due to the development of residential small cogeneration units, solar, batteries, and wind could influence more customers going “off-grid” as electric rates continue to be high in the Upper Peninsula.
4. Transportation energy: Percentage of electric vehicles sales in Michigan increases to 10% by 2025. (One out of every ten vehicles on the road in Michigan is electric.)
5. Increase the EWR resources to at least the EWR potential study maximum achievable potential levels.<sup>24</sup>
6. Large electric users: Reduced load due to customers adding CHP, batteries, and/or behind the meter generation (btmg) to offset the high electric rates.

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<sup>24</sup> For maximum achievable potential levels, see the supplemental potential study for the Lower Peninsula, [http://www.michigan.gov/documents/mpsc/MI\\_Lower\\_Peninsula\\_EE\\_Potential\\_Study\\_Final\\_Report\\_08.11.17\\_598053\\_7.pdf](http://www.michigan.gov/documents/mpsc/MI_Lower_Peninsula_EE_Potential_Study_Final_Report_08.11.17_598053_7.pdf); See also supplemental potential study for the Upper Peninsula, [http://www.michigan.gov/documents/mpsc/UP\\_EE\\_Potential\\_Study\\_Final\\_Report--memorandum\\_08.09.17\\_598056\\_7.docx](http://www.michigan.gov/documents/mpsc/UP_EE_Potential_Study_Final_Report--memorandum_08.09.17_598056_7.docx).

## IX. Michigan IRP Modeling Input Assumptions and Sources

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

	Value	Sources
<b>1 - Analysis Period</b>	<ul style="list-style-type: none"> <li>• 5, 10, 15 years minimum; longer study periods encouraged</li> </ul>	
<b>2 - Model Region</b>	<ul style="list-style-type: none"> <li>• Michigan, plus applicable RTO region as deemed necessary by utility.</li> </ul>	
<b>3 - Economic Indicators and Financial Assumptions (e.g. Weighted Average Cost of Capital)</b>	<ul style="list-style-type: none"> <li>• Utility-specific</li> </ul>	<ul style="list-style-type: none"> <li>• Prevailing value from most recent MPSC proceedings</li> </ul>
<b>4 - Load Forecast</b>	<ul style="list-style-type: none"> <li>• 50/50 forecast</li> <li>• Forecasts other than 50/50 utilized to align with scenario and/or sensitivity descriptions should be documented and justified.</li> </ul>	<ul style="list-style-type: none"> <li>• Utility forecast and applicable RTO forecasts</li> </ul>
<b>5 - Unit Retirements</b>	<ul style="list-style-type: none"> <li>• Retirements driven by maximum age assumption or economics</li> <li>• Public announcements on retirements</li> </ul>	<ul style="list-style-type: none"> <li>• MISO or PJM documented fuel type retirements</li> <li>• All retirement assumptions must be documented</li> </ul>
<b>6 - Natural Gas Price</b> <i>nominal dollars \$/MMBtu</i>	<ul style="list-style-type: none"> <li>• Forecasts utilized should align with scenario and/or sensitivity descriptions; Gas prices should include transportation costs.</li> </ul>	<ul style="list-style-type: none"> <li>• NYMEX futures (applicable for near-term forecasts only)</li> <li>• EIA Annual Energy Outlook</li> <li>• EIA Table 3: Energy Prices</li> <li>• EIA Short-Term Energy Outlook Reports</li> <li>• If utility-specific data is utilized, it should be justified and made available to all intervening parties.</li> </ul>
<b>7 - Coal Price</b> <i>nominal dollars \$/MMBtu</i>	<ul style="list-style-type: none"> <li>• Forecasts utilized should align with scenario and/or sensitivity descriptions; Coal prices should include transportation costs.</li> </ul>	<ul style="list-style-type: none"> <li>• EIA Coal Production and Minemouth Prices by Region</li> <li>• EIA Annual Energy Outlook</li> <li>• EIA Table 3: Energy Prices</li> <li>• EIA Short-Term Energy Outlook Reports/Annual Reports</li> <li>• If utility-specific data is utilized, it should be justified and made available to all intervening parties.</li> </ul>
<b>8 - Fuel Oil Price</b> <i>nominal dollars \$/MMBtu</i>	<ul style="list-style-type: none"> <li>• Forecasts utilized should align with scenario and/or sensitivity descriptions.</li> </ul>	<ul style="list-style-type: none"> <li>• If utility-specific data is utilized, it should be justified and made available to all intervening parties.</li> </ul>
<b>9 - Energy Waste Reduction Savings</b> <i>MWhs</i>	<p>Business as Usual Scenario:</p> <ul style="list-style-type: none"> <li>• For electric utilities earning a financial incentive, base case energy reductions of 1.5% per year as a net to load forecast.</li> <li>• For non-incentive earning electric utility, mandated annual incremental savings (1.0%) as a net to load.</li> <li>• Not less than 35% of the state's electric needs should be met through a combination of energy waste reduction and renewable energy by 2025, as per Public Act 342 Section 1 (3).</li> </ul> <p>EWR Business as Usual Sensitivities:</p> <ul style="list-style-type: none"> <li>• For savings beyond mandate, incorporate EWR as an optimized generation resource.</li> </ul> <p>Emerging Technologies Scenario:</p> <ul style="list-style-type: none"> <li>• Ramp up EWR savings at least 2.5% over the course of four years, using EWR Cost Supply Curves provided in the 2017 Supplemental Potential Study for More Aggressive Potential (e.g., with 100% incremental cost of incentives, no cost cap and emerging technologies assumptions.)</li> <li>• Consider load shape of EWR measures so on-peak capacity reduction associated with EWR can be reflected.</li> </ul>	<ul style="list-style-type: none"> <li>• Utility EWR plan and reconciliation filings</li> <li>• 2016 EWR Potential Studies for Consumers Energy and DTE Energy</li> <li>• 2017 Lower Peninsula EWR Basic Potential Estimate</li> <li>• 2017 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential</li> <li>• 2017 Lower Peninsula EWR Cost Supply Curves</li> </ul>
<b>10 - Energy Waste Reduction Costs</b> <i>nominal dollars per kWh</i>	<ul style="list-style-type: none"> <li>• Current average levelized costs as defined in 2016/2017 Potential Studies and Supplemental Modeling reflecting aggressive and cost effective program savings goals.</li> </ul>	<ul style="list-style-type: none"> <li>• 2016 EWR Potential Studies for Consumers Energy and DTE Energy</li> <li>• 2017 Lower Peninsula EWR Basic Potential Estimate</li> <li>• 2017 Upper Peninsula EWR Supplemental Potential Study – Estimating More Aggressive EWR Potential</li> <li>• 2017 Lower Peninsula EWR Cost Supply Curves</li> </ul>

<b>11 - Demand Response Savings</b> <i>MWs</i>	<ul style="list-style-type: none"> <li>• 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).</li> <li>• Technical, economic and achievable levels of demand response as applicable to the scenario.</li> </ul>	<ul style="list-style-type: none"> <li>• As defined by 2017 Demand Response Potential Study</li> </ul>
<b>12 - Demand Response Costs</b> <i>nominal dollars per MW</i>	<ul style="list-style-type: none"> <li>• Costs/MW by program including all payments, credits, or shared savings awarded to the utility through regulatory incentive mechanism.</li> </ul>	<ul style="list-style-type: none"> <li>• As defined by 2017 Demand Response Potential Study</li> </ul>
<b>13 - Renewable Capacity Factors</b>		<ul style="list-style-type: none"> <li>• If utility-specific data is utilized, it should be justified and made available to all intervening parties.</li> </ul>
<b>14 - Renewable Capital Costs and Fixed O&amp;M Costs</b> <i>nominal dollars per kWh</i>  <i>and</i>  <b>Renewable Fixed O&amp;M Costs</b> <i>nominal dollars per kW</i>	<ul style="list-style-type: none"> <li>• Wind, solar, biomass, landfill gas</li> <li>• Combined heat and power (CHP)</li> </ul>	<ul style="list-style-type: none"> <li>• National Renewable Energy Lab's <i>Annual Technology Baseline Report</i></li> <li>• Department of Energy's <i>Wind Technologies Market Report</i></li> <li>• Lawrence Berkeley National Lab's <i>Tracking the Sun and Utility Scale PV Cost</i></li> <li>• Assumptions based on utility experience (Michigan specific and/or RTO - MISO/PJM)</li> <li>• 2015 Michigan Renewable Resource Assessment</li> <li>• Department of Energy's <i>Wind Vision Study</i></li> <li>• Department of Energy's <i>Sunshot Vision Study</i></li> <li>• Lazard's Levelized Cost of Storage Analysis 2.0</li> <li>• If utility is using specific data not publicly sourced, must be justified and made available to all intervening parties.</li> </ul>
<b>15 - Other/Emerging Alternatives</b>	<ul style="list-style-type: none"> <li>• Changes to operation guides</li> <li>• Options which improve reliability (SVC, HVDC, volt/VAR)</li> <li>• 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.</li> <li>• Utility-scale (e.g., integrated gasification combined cycle, combined heat and power, pumped hydro storage, voltage optimization)</li> <li>• 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))</li> <li>• Other Distributed Resources (e.g., stationary batteries, electric vehicles, thermal storage, compressed air, flywheel, solid rechargeable batteries, flow batteries).</li> </ul>	<ul style="list-style-type: none"> <li>• Assumptions and parameters other than costs that are associated with the technologies and options (such as future adoption rates) should be afforded flexibility due to those technologies' and options' presently unconventional nature. However, the utility should still show that all assumptions and parameters are reasonable and were developed from credible sources.</li> <li>• 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.</li> </ul>
<b>16 - Wholesale Electric Prices</b>		<ul style="list-style-type: none"> <li>• Documentation for wholesale price forecast must be provided to all intervening parties.</li> </ul>

## **X. Additional IRP Requirements and Assumptions**

1. Utility-specific assumptions for discount rates, weighted average cost of capital and other economic inputs should be justified and the data shall be made available to all parties.
2. Prices and costs should be expressed in nominal dollars.
3. The capacity import and export limits in the IRP model for the study horizon should be determined in conjunction with the applicable RTOs and transmission owners resulting from the most current and planned transmission system topology. Deviations from the most recently published import and export limits should be explained and justified within the report.
4. Environmental benefits and risk must be considered in the IRP analysis.
5. Cost and performance data for all modeled resources, including renewable and fossil fueled resources, as well as storage, energy efficiency and demand response options should be the most appropriate and reasonable for the service territory, region or RTO being modeled over the planning period. Factors such as geographic location with respect to wind or solar resources and data sources that focus specifically on renewable resources should be considered in the determination of initial capital cost and production cost (life cycle/dispatch).
6. Models should account for operating costs and locational, capital and performance variations. For example, setting pricing for different tranches if justified.
7. Capacity factors should be projected based on demonstrated performance, consideration of technology improvements and geographic/locational considerations. Requirements for renewable capacity factors are described in the Michigan IRP Modeling Input Assumptions and Sources in the previous section of this draft.
8. The IRP model should optimize the incremental EWR and renewable energy to achieve the 35% goal. However, the model should not be arbitrarily restricted to a 35% combined goal of EWR and renewable energy. Exceeding the combined EWR and renewable energy goal of 35% by 2025 shall not be grounds for determining that the proposed levels of peak load reduction, EWR and renewable energy are not reasonable and cost effective.
9. Prior to modeling the Business as Usual, Emerging Technologies, Environmental Policy, or High Market Price Variant Scenarios, the utilities shall consider and prescreen all of the technologies, resources, and generating options listed in the Michigan IRP Modeling Input Assumptions and Sources in the previous section of this draft. These findings will then be presented and discussed via at least one stakeholder meeting with written comments from stakeholders taken into consideration. The options having potential viability are then considered in modeling.
10. 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.

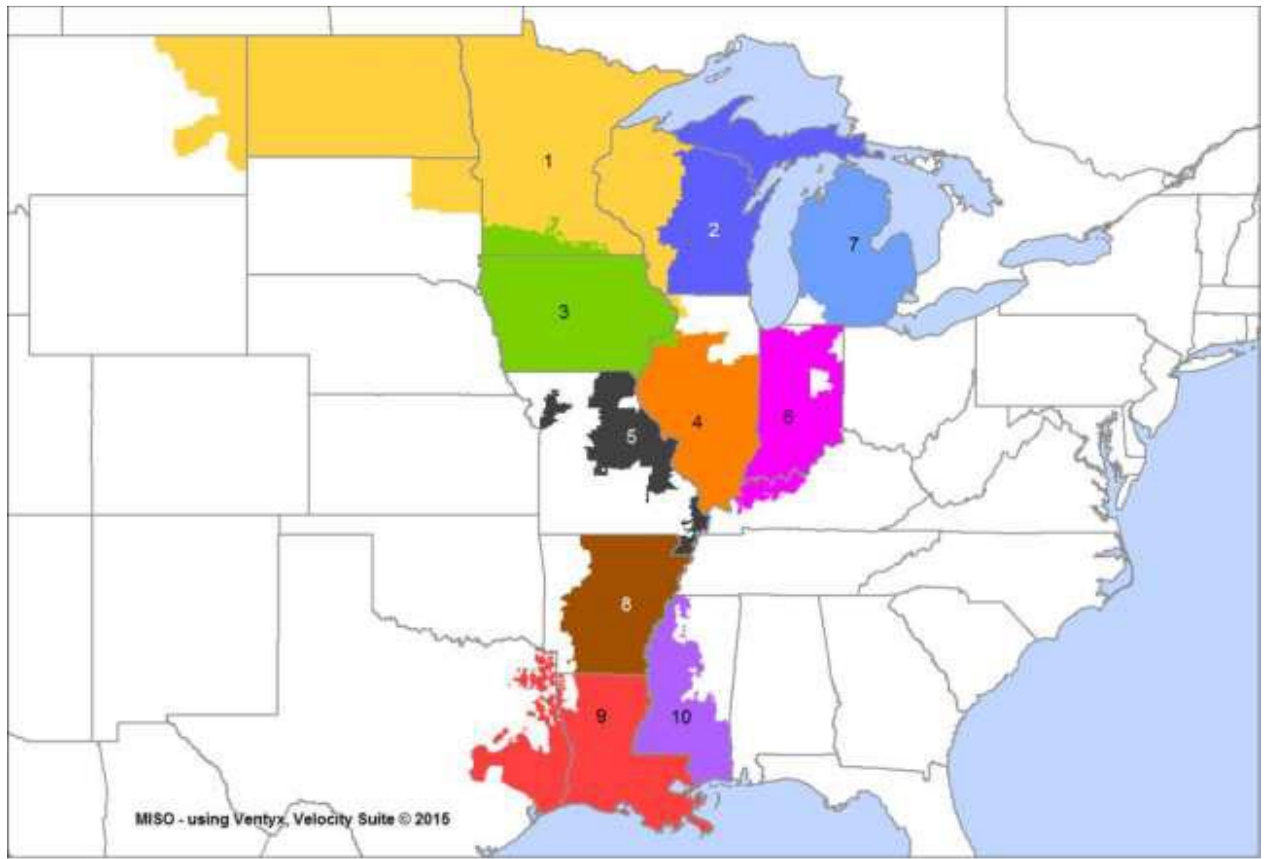


11. Consider all supply and demand-side resource options on equal merit, allowing for special consideration for instances where a project or a resource need requires rapid deployment.
12. In modeling each scenario and sensitivity evaluated as part of the IRP process, the utility shall allow the model to select retirement of existing generation resources, rather than limiting retirements to input assumptions.
13. Recognize capacity and performance characteristics of variable resources.
14. Recognize the costs and limitations associated with fossil-fueled and nuclear generation.
15. Take into consideration existing power purchase agreements, green pricing and/or other programs.
16. 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.

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

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

## Appendix B: Map of MISO Local Resource Zones



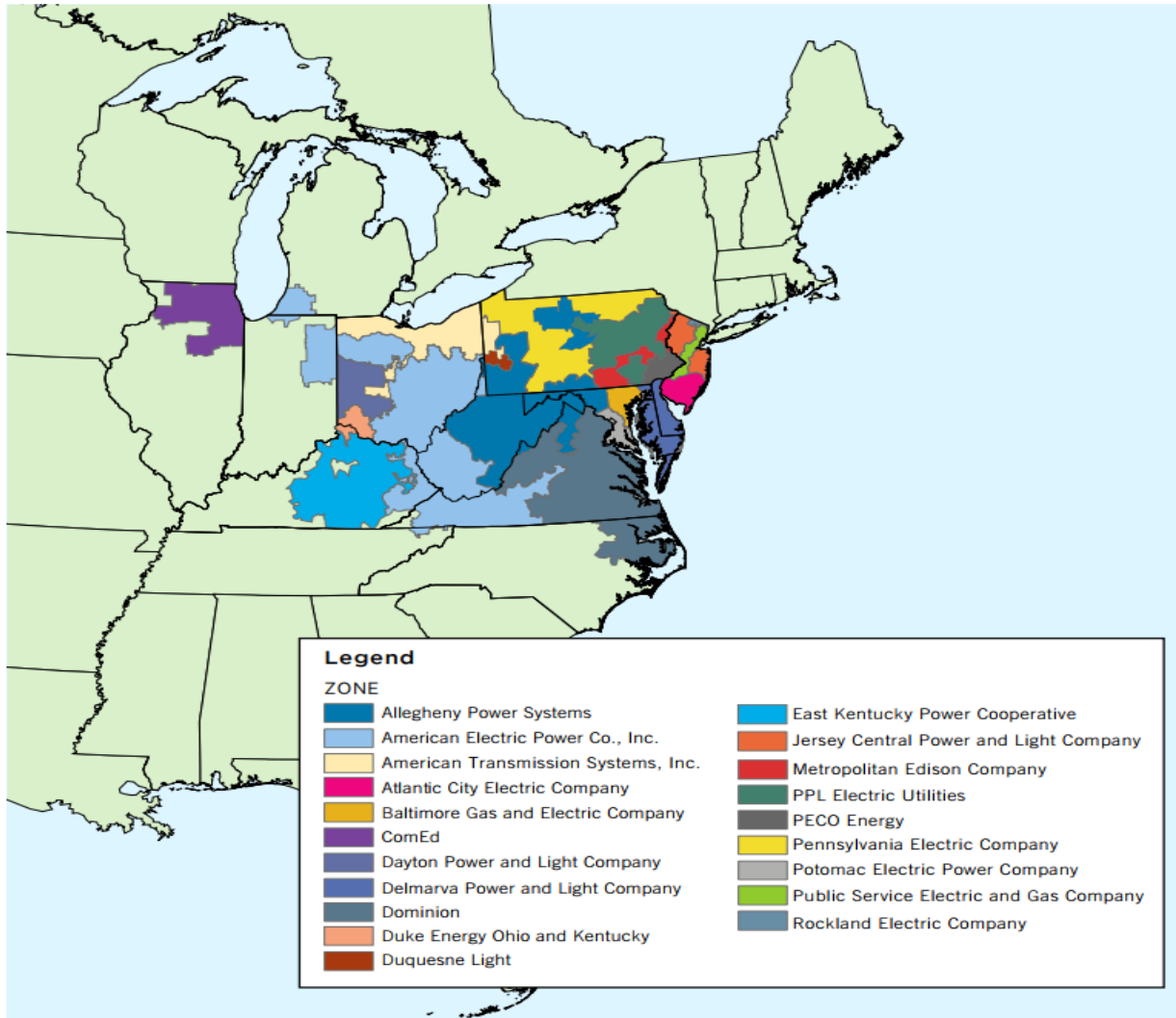
MISO Zone 1 - Rate regulated electric utility - Northern States Power-Wisconsin

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

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

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

## Appendix C: Map of PJM Local Deliverability Areas



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

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

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

- (a) Conduct an assessment of the potential for energy waste reduction in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable.
- (b) Conduct an assessment for the use of demand response programs in this state, based on what is economically and technologically feasible, as well as what is reasonably achievable. The assessment shall expressly account for advanced metering infrastructure that has already been installed in this state and seek to fully maximize potential benefits to ratepayers in lowering utility bills.
- (c) Identify significant state or federal environmental regulations, laws, or rules and how each regulation, law, or rule would affect electric utilities in this state.
- (d) Identify any formally proposed state or federal environmental regulation, law, or rule that has been published in the Michigan Register or the Federal Register and how the proposed regulation, law, or rule would affect electric utilities in this state.
- (e) Identify any required planning reserve margins and local clearing requirements in areas of this state.
- (f) Establish the modeling scenarios and assumptions each electric utility should include in addition to its own scenarios and assumptions in developing its integrated resource plan filed under subsection (3), including, but not limited to, all of the following:
  - (i) Any required planning reserve margins and local clearing requirements.
  - (ii) All applicable state and federal environmental regulations, laws, and rules identified in this subsection.
  - (iii) Any supply-side and demand-side resources that reasonably could address any need for additional generation capacity, including, but not limited to, the type of generation technology for any proposed generation facility, projected energy waste reduction savings, and projected load management and demand response savings.
  - (iv) Any regional infrastructure limitations in this state.
  - (v) The projected costs of different types of fuel used for electric generation.
- (g) Allow other state agencies to provide input regarding any other regulatory requirements that should be included in modeling scenarios or assumptions.
- (h) Publish a copy of the proposed modeling scenarios and assumptions to be used in integrated resource plans on the commission's website.
- (i) Before issuing the final modeling scenarios and assumptions each electric utility should include in developing its integrated resource plan, receive written comments and hold hearings to solicit public input regarding the proposed modeling scenarios and assumptions.

STATE OF MICHIGAN  
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

\* \* \* \* \*

<b>In the matter of, on the Commission's own motion to implement the provisions of Section 6t(1) of 2016 PA 341</b>	) ) ) ) ) <hr/>	<b>Case No. U-18418</b>
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**PROOF OF SERVICE**

Jennifer M. Brooks, being duly sworn, deposes and says that on August 31, 2017, A.D., she emailed a copy of the attached Report to the persons as shown on the attached list.

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Jennifer M. Brooks

Subscribed and sworn to before me  
this 31<sup>st</sup> day of August, 2017.

---

Lacie Lea Latimore  
Notary Public – State of Michigan  
County of Eaton  
My Commission Expires July 3, 2021

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